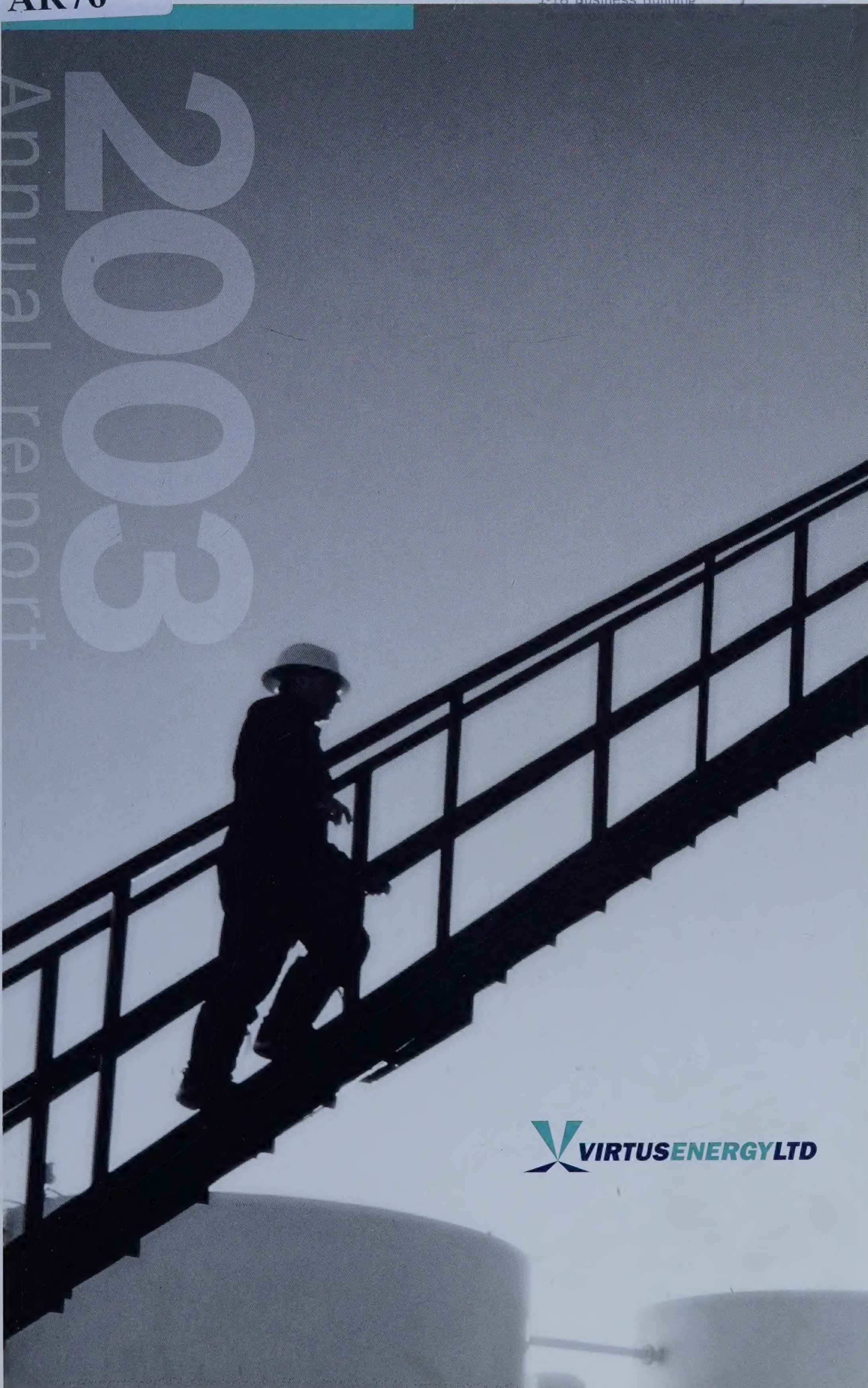
2003 Annual report



VIRTUS ENERGY LTD

Corporate Profile

Virtus Energy Ltd. is a Calgary based emerging oil and natural gas company with a primary goal: to become a leading growth and value-driven exploration and production company. By implementing its strategic plan in key focus areas located throughout the Western Canadian Sedimentary Basin, Virtus is well positioned to achieve its ambitious growth plans for building value from its operations for the benefit of its shareholders. Common shares of Virtus are listed for trading on the TSX Venture Exchange under the symbol VEL.

Annual Meeting

Shareholders are cordially invited to attend the Annual General Meeting of Virtus Energy Ltd. to be held on Wednesday, June 2, 2004 at 3:00 p.m. (Calgary time), in the Cardium Room of the Calgary Petroleum Club, 319 Fifth Avenue S.W., Calgary, Alberta. Shareholders who are unable to attend the Meeting are requested to complete and return the Instrument of Proxy to Olympia Trust Company at their earliest convenience.

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Performance highlights

YEARS ENDED DECEMBER 31,	2003	2002	CHANGE
			%
OPERATING HIGHLIGHTS			
Production			
Oil (bbls/d)	483	281	72
Natural gas (mcf/d)	789	132	498
NGLs (bbls/d)	6	5	20
Total (boe/d)	621	308	102
Realized prices			
Oil ($/bbl)	33.88	33.21	2
Natural gas ($/mcf)	6.09	3.90	56
NGLs ($/bbl)	29.27	19.24	52
Average ($/boe)	34.74	32.35	7
Operating netback			
Average ($/boe)	18.74	15.80	19
Reserves			
Oil & NGLs			
Proved (mbbls)	938	769	22
Probable (mbbls)	195	202	(3)
Natural gas			
Proved (mmcf)	1,447	1,780	(19)
Probable (mmcf)	558	1,433	(61)
Land			
Undeveloped (net acres)	29,295	44,120	(34)
	$	$	%
FINANCIAL HIGHLIGHTS			
Petroleum & natural gas sales	7,870,050	3,637,604	116
Cash flow from operations	2,724,093	835,934	225
Per share	0.08	0.04	100
Net loss	(238,503)	(214,850)	–
Per share	(0.01)	(0.01)	–
Capital expenditures	12,560,697	6,545,554	92
Total assets	19,826,527	12,922,242	53
Bank debt	2,075,000	–	–
Working capital (surplus) deficit	2,234,369	(309,859)	–
Shareholders' equity	13,141,292	10,632,805	24
Common shares outstanding (#)	36,162,431	30,980,268	17

$0.08

(per share)

delivering

Emerging companies in the highly competitive Canadian oil and gas industry require a defined growth strategy, a solid management team and the financial capacity to perform. Virtus has developed a sound business and implementation plan, and has assembled a team that can deliver meaningful results. We believe our focused approach to full cycle exploration and development complemented by strategic acquisitions as well as prudent risk management will deliver long-term value gains for our shareholders.

President's message

Building on the business plan implemented in 2002, the year 2003 was one of significant and meaningful progress at Virtus. We completed key steps in the development of our Company, making important strides both operationally and financially. Here are our results.

Operations

BUILDING THE FOUNDATION
– 80% of Effort and Capital

As set out in our Annual Report a year ago, our Company's strategy for building an asset base in Western Canada involves the acquisition and exploitation of oil reserves in areas that also have multi-zone gas targets. During 2003, we focused primarily on oil reserves simply because they were more affordable than higher priced, extremely competitive natural gas reserves acquisitions, and as a result, implemented a program of acquiring and optimizing oil producing assets while drilling and recompleting for natural gas reserve additions. Although we intend to maintain our focus on acquiring oil properties, we will pursue natural gas acquisitions that provide upside opportunities or infrastructure ownership. Our goal is to have a balanced base of oil and gas production.

Consistent with our business strategy, we directed almost 50% of our 2003 capital expenditures towards building a production base capable of providing a stable source of revenue for re-investment. In April of 2003, we closed the acquisition of producing properties at Seal, Alberta, thereby adding 300 boe/d of operated production. With facility expansions completed late in the year that have provided a four-fold increase in the fluid handling capability at the Virtus operated production battery, Seal is now our Company's largest producing area at 540 boe/d or about 68% of total corporate production. Approximately 70% of our 2003 total capital program was allocated to acquisition, drilling, optimization and plant expansion initiatives at Seal.

This same acquisition and exploitation model was previously used at our Battle Creek, Saskatchewan property in 2002. Virtus acquired this oil producing property with plans to exploit several up-hole natural gas horizons. Step-out drilling and well tie-ins conducted in 2003 have resulted in the addition of low rate shallow natural gas production. Current production from this property is approximately 180 boe/d.

During the year, we also made significant progress in streamlining our Company's asset base. Property dispositions of non-core assets amounting to $1,972,030 were offset by $5,903,148 of property acquisitions. Of the original 18 properties held by Virtus in 2001, only eight of these properties remain. As of January 1, 2004, over 78% of our Company's proved plus probable reserves value and 90% of our production is attributable to the Seal and Battle Creek properties.

In order for the Company to participate in drilling ventures on a sustainable and statistically favourable basis, we continued to build a production and cash flow base sufficient to fund an annual drilling program. In our medium risk operating areas, average well costs are approaching $750,000 per successful well, and as a consequence, each drilling decision and the resulting outcome can significantly affect our revenue and cash flow stream. During 2003, we managed our operating risk by concentrating on core area growth initiatives and, where appropriate, bringing partners into new drilling projects.

Unfortunately, our drilling results for the year were disappointing. Although we participated in 9 gross (3.7 net) wells, only 44% of these wells were successful. At Spirit River in northwest Alberta, one well was drilled for bypassed Bluesky-Gething natural gas, but was dry and abandoned. At Wildwood in north-central Alberta, Virtus acquired five sections of undeveloped lands, secured a joint venture partner for 75% of well costs and drilled two wells for medium-depth, multi-zone gas targets. The first well encountered two gas zones, one of which was placed on production in September. The second well was drilled into the same geophysically defined feature, but did not encounter reservoir and was abandoned. Although our first venture into this area was economically successful, it was technically challenging. Internally generated prospects and farmin opportunities in the Wildwood area will continue to be pursued in 2004 utilizing a refined technical model.

HIGH RISK, HIGH REWARD PROJECTS – 20% of Effort and Capital

During the year, we made excellent progress in building a portfolio of high risk, high reward natural gas prospects in northeastern British Columbia. At Adsett, the Company successfully negotiated the farmout and option of its 8,235 gross (2,745 net) acre undeveloped land block to an intermediate oil and gas producer. In accordance with the farmout agreement, the operator acquired 25 kilometres of new seismic on Company lands and subsequently drilled a

deep test well with Virtus participating for an 8.33% working interest. The well was cased in late December and completion operations on the Slave Point/Sulphur Point formations, which commenced in late January, resulted in moderate natural gas flow rates and good pressures, but significant associated water. Several attempts to segregate the inflow of water were unsuccessful and the well was plugged back for up-hole potential. Completion and testing of a shallower Debolt zone commenced in mid-February resulting in natural gas rates approaching 1 mmcf/d, but with declining pressures and indications of a low permeability reservoir. Consequently, the well was abandoned. Although it was not commercial in the primary targets, we were encouraged that the well encountered structure, porosity and flows of natural gas. Additional seismic is proposed later in 2004 to further delineate this prospect.

Late in the third quarter, the Company and its original joint venture partners in the Adsett lands acquired the key land tracts to a second high risk prospect at Tenaka, also located in northeastern British Columbia. This property, which is in the vicinity of other recent high profile drilling activity, is a high risk structural feature that is evident on newly acquired seismic. During 2004, we plan to acquire additional seismic on the Tenaka prospect in order to further identify the potential of the play. Activities have also commenced to secure a third party farmin partner.

Financial

Virtus achieved significant year-over-year growth in its financial performance. Petroleum and natural gas sales increased 116% to $7,870,050, cash flow from operations jumped 225% to $2,724,093 or $0.08 per share and shareholders' equity increased 24% to $13,141,292. Average operating netbacks received by the Company improved 19% to $18.74/boe. While we believe in a conservative and strategic approach to financial management, in today's economic environment, we also recognize the need to be flexible and analytical in our response to new opportunities.

Looking Ahead

The consensus forecast of commodity prices looks promising for companies prepared to grow through the drill bit. As a result, Virtus has expanded its technical team and taken positive steps to build a drilling prospect inventory in a new core area in the greater Fort St. John region of British Columbia. Acquisition opportunities will be pursued in core areas, but quality assets remain in great demand. Despite this fact, we will continue to build, exploit and add to our asset base in existing and new focus areas. Area dominance and prudent risk management are the cornerstones of our operating strategy which, when combined with infrastructure ownership, provide Virtus with operational control while lowering our per unit costs of production.

Fiscal 2003 marked the first full year of focused operations since reorganizing and recapitalizing the Company in 2002. We have accomplished a great deal in just one year and look forward to taking the next important steps towards sustained growth and profitability.

People

Subsequent to closing the Seal acquisition, Mr. Dave Humphreys was appointed Vice President, Operations of the Company. In addition, my colleagues and I extend a warm welcome to Mr. Andy St.Onge who joined the Company as Vice President, Exploration and Mr. Thom Bainbridge as Consulting Geologist. In early March of 2004, we further strengthened our technical team with the addition of Mr. Kerry Rawson as Manager, Engineering and Mr. Gordon de Metz as Chief Geologist. With these individuals now in place, Virtus is well positioned to execute the next phase of drilling activity.

Acknowledgements

On behalf of the Board of Directors, I sincerely thank our employees, consultants and business associates for their efforts over the past year – we value their commitment. I am also grateful to our shareholders for your support and confidence, and I extend an invitation to join us at our Annual Meeting scheduled for June 2, 2004.

On behalf of the Board of Directors,

PETER A. CARWARDINE

President & Chief Executive Officer

April 1, 2004


VIRTUS


621
(boe/d)

building

In 2003, our production increased to an average 621 boe/d, up 102% from a year ago. Our target for 2004 is to grow our Western Canadian production base by drilling a portfolio of low, medium and high risk prospects that build on synergies with our existing infrastructure.

Operations and drilling review

Virtus focused its 2003 efforts in four key areas of the Western Canadian Sedimentary Basin. Approximately 83% of the Company's exploration, development and acquisition capital was spent in the Seal, Alberta; Battle Creek, Saskatchewan and northeastern British Columbia focus areas. The remaining capital expenditures were applied towards exploitation of its non-core properties and the evaluation of new areas for possible future involvement.

Operating Philosophy

Virtus continues to pursue and develop two strategic models for exploring, developing, acquiring and divesting.

Area Dominance. In its low-to-medium risk focus areas, Virtus strives to become the dominant local operator with majority ownership in production, reserves, infrastructure and undeveloped land. The Company will gain superior technical knowledge of the area, and as a result, exploitation, development, acquisition and exploration opportunities will be pursued.

Managed Risk. By allocating up to 80% of the Company's time, effort and capital towards low-to-medium risk, operated activities in selected focus areas, Virtus will expand its production base and opportunity inventory.

Up to 20% of the Company's annual capital will be allocated to building an inventory of high risk, high reward exploratory prospects through land and seismic acquisition programs with an objective to farmout these prospects to third parties within one year of their acquisition.

The following are the principal drivers of the Company's exploration, development, acquisition and disposition strategy:

EXPLORATION

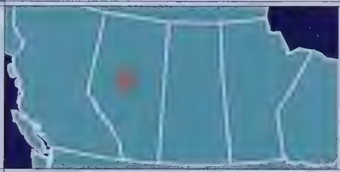
- **Operate where possible**
  – Control the activity
- **Acquire key land tracts early**
  – The competition is fierce
- **Target multi-zone prospects that are repeatable**
  – Decreases risk and increases success
- **Pursue areas accessible to existing infrastructure**
  – Shorten the time to production
- **Maintain at least a 50% working interest**
  – Balance risk and reward

DEVELOPMENT

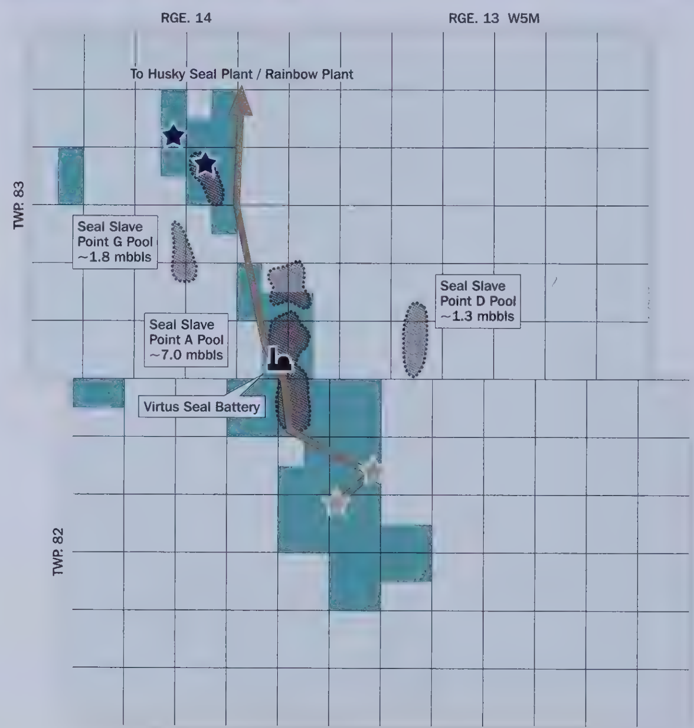
- **Operate at least 75% of activity**
  – Control and area dominance will result
- **Optimize existing production in all zones**
  – Maximize the value of assets
- **Exploit bypassed pay opportunities**
  – Know what you control
- **Utilize existing seismic and farmin where appropriate**
  – Shorten the drilling cycle time
- **Target areas with underutilized infrastructure**
  – Allocate greater capital to drilling
- **Strive for at least a 75% working interest**
  – Consolidate early

ACQUISITIONS AND DISPOSITIONS

- **Identify upside on acquisitions and dispositions**
  – Significant risked value exists
- **Buy partner interests in existing focus areas**
  – Focus area dominance will result
- **Buy minor interests as entry to new focus areas**
  – Gain a position early
- **Pursue acquisitions with drill bit growth potential**
  – Value additions to be gained
- **Sell or swap properties prior to full maturity**
  – Upgrade the quality of the portfolio



seal alberta



- High working interest production
- High quality, light sweet crude oil
- Operated production and well developed infrastructure
- Multi-zone natural gas potential

Property Review

Medium Risk Prospects

SEAL, ALBERTA

The purchase, optimization and exploitation of the Seal property was a key accomplishment for Virtus in 2003. The acquisition included 300 boe/d of operated production, a battery facility, ownership in pipeline infrastructure and 3,750 net acres of undeveloped land in north-central Alberta. Prior to closing the acquisition in April of 2003, Virtus held a 55% working interest in two operated Slave Point light oil wells that were being tied into the Seal battery. Subsequent to closing, the Company completed a detailed well review in order to optimize the property's production, and as a result, wells were identified and several workovers were successfully completed. One recompletion resulted in a net production gain of 500 mcf/d of natural gas and two shut-in oil wells were reactivated, resulting in an additional 65 boe/d of net production. The facility was expanded with the addition of a free water knockout, water disposal pumps and numerous electrical and instrumentation upgrades. Two additional shut-in wells were also recompleted as water disposal wells to handle increased water volumes from current and future wells. This facility expansion has provided a four-fold increase in fluid handling capacity such that at year-end, average production from the Seal property was 435 boe/d, a

45% improvement over April 2003. The net investment in the facility expansion, including the two additional disposal wells and associated pipelines, was approximately $1,600,000.

In January of 2004, Virtus acquired a joint venture partner's interest in three producing oil wells and 1,100 acres of undeveloped land at Seal, resulting in a net addition of 50 bbls/d. The Company has identified two locations on the acquired lands for future light oil drilling potential. In addition, two drilling locations on 100% owned lands at Seal have been constructed, a joint venture partner is in place and follow-up locations have been identified depending upon initial well success. These initial wells will be drilled prior to spring breakup and all of these locations are within 2 kilometres of existing, underutilized pipeline infrastructure. With 4,848 net acres of undeveloped land and access to a significant 2-D and 3-D seismic database, the expansion opportunities for this area are encouraging. Seal has now become a significant asset for Virtus in terms of production, cash flow and reserves.

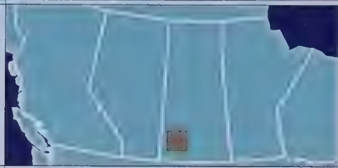
VETERAN, ALBERTA

The Veteran property, located in the Provost region of eastern Alberta, provided solid cash flow for Virtus in 2003. Although this is a high operating cost property, operating efficiencies were improved and production volumes were optimized during the year through the Virtus owned and operated battery facility. Consistent with the Company's objective to maximize the value of its assets, in June of 2003 Virtus closed the sale of a 30% interest in the property with proceeds of $600,000 applied to reduce bank debt incurred as a result of the Seal property acquisition. During 2003, average production from the Veteran property was 123 gross (105 net) bbls/d.

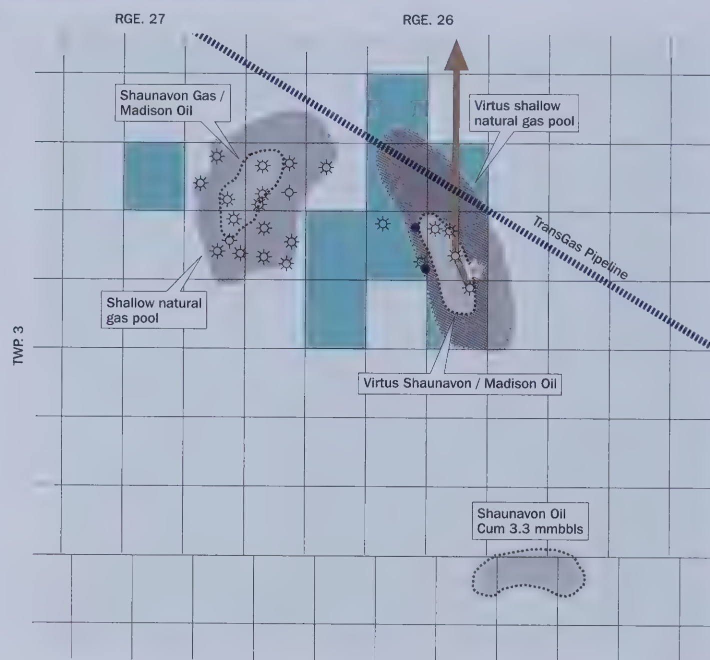
In February of 2004, coincident with the acquisition of a partner's interest at Seal, Virtus sold a further 30% interest in the Veteran property for $600,000 to a third party. Virtus expects to sell its remaining 40% interest in this operated property, now producing 44 bbls/d net, prior to year-end.

WILDWOOD, ALBERTA

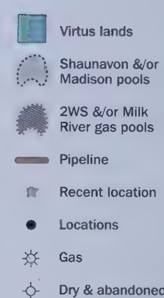
The Wildwood prospect in north-central Alberta represents an entry into a new operating area for Virtus. During 2002 and 2003, the Company acquired a total of 4,480 gross (3,280 net) acres of land for Cretaceous and Nordegg gas potential on this geophysically identified prospect. The Company obtained a farmin partner for 75% of the costs of the initial well and participated for the remaining 25% working interest. Virtus will revert to a 62.5% working interest in the well after payout.



battle creek saskatchewan



- **100% working interest in oil production**
- **Operated production and infrastructure**
- **Uphole multi-zone natural gas reserves established**

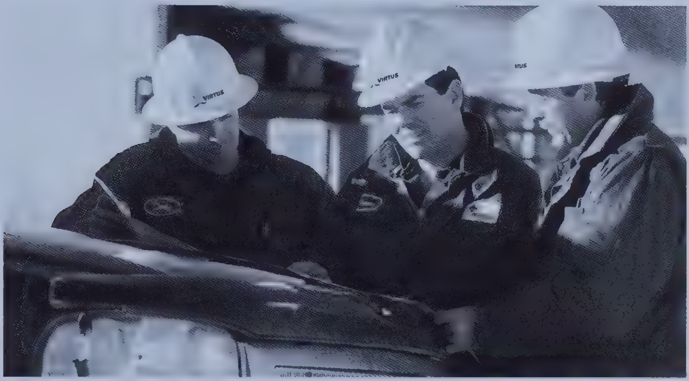


The first well to test this operated natural gas prospect at Wildwood was drilled and completed in the third quarter of 2003 and tied in to pipeline infrastructure early in the fourth quarter. Initial production from the well resulted in gross rates of approximately 1 mmcf/d, declining to 750 mcf/d by year-end. A follow-up location to the discovery well was drilled late in 2003; unfortunately, it did not encounter porous reservoir and was subsequently abandoned. Although the Company's first venture into this area was economically successful, it was technically challenging. Internally generated prospects and farmin opportunities in the Wildwood area will continue to be pursued in 2004 utilizing a refined technical model.

BATTLE CREEK, SASKATCHEWAN

The Battle Creek property is located in southwestern Saskatchewan approximately 30 kilometres north of the United States border. Virtus owns a 100% working interest in the oil pool, which in 2003 produced an average 159 bbls/d from the deeper Shaunavon and Madison formations.

In late 2002, Virtus recompleted a former producing oil well and drilled four shallow gas wells to exploit bypassed Cretaceous natural gas potential on Company lands. Early in the second quarter of 2003, Virtus sold a 45% interest in these shallow natural gas wells and shallow rights to an industry partner for $1,050,000. The proceeds from this partial sale were re-invested to equip and tie-in four wells for natural gas production.



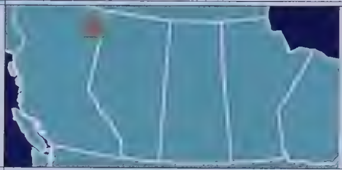
In early December, the Company and its joint venture partner drilled an additional well for a seismically defined shallower target, resulting in the well's completion and tie-in by month-end. Combined oil and natural gas production from the Battle Creek property is currently averaging 180 boe/d net to the Company. Virtus has identified two additional shallow gas locations on Company lands for follow-up drilling in 2004.

High Impact Prospects

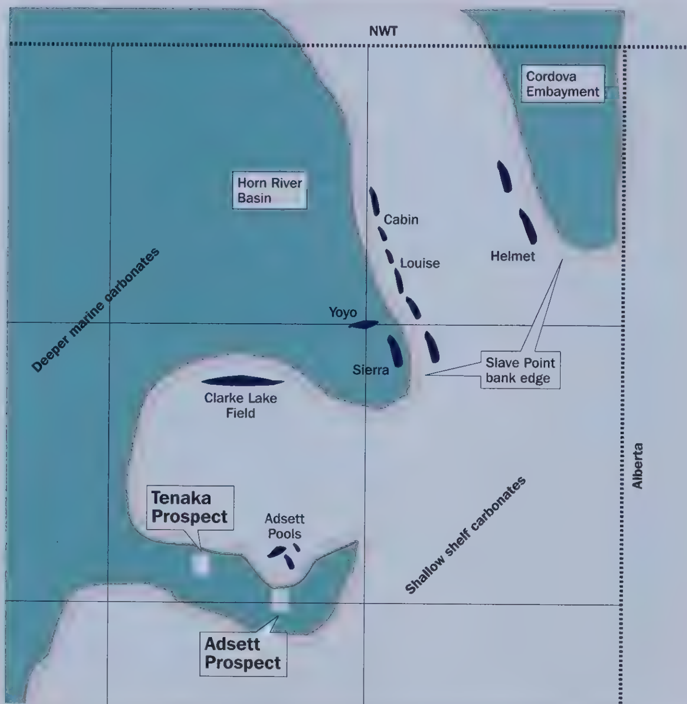
Virtus' acquisition of the Adsett lands in northeastern British Columbia in 2002 represented the Company's entry into high impact projects. Widely known as a geologically prospective Province, the Government of British Columbia has significantly improved its regulatory and economic framework with the objective of encouraging oil and gas investment.

ADSETT, BRITISH COLUMBIA

In 2002, Virtus and its two joint venture partners acquired 12 gas spacing units (sections) of undeveloped Crown lands south of the main Adsett producing field for further geophysical evaluation and eventual deep drilling. Seismic data acquired by the partners provided indications of significant structure and closure capable of containing hydrocarbons in several zones of interest. Recognizing the high risk, high reward nature of the project, a third party farmin partner was obtained for the acquisition of additional seismic data in order to confirm a potential drilling location. With approximately 100 kilometres of 2-D seismic data indicating significant structure, in May of 2003 the farmin partner elected to drill a 2,600 metre Slave Point well to test the prospect. Virtus participated for an 8.33% working interest in the well and the associated drilling and completion costs, which totaled approximately $290,000 net. Although the lands are in close proximity to pipeline and road infrastructure, surface construction delays pushed drilling commencement to November. Drilling continued for approximately 40 days, with total depth reached in late December. Intermediate casing was set to the top of the Slave Point formation and the rig was released. Log and well data indicated confirmation of structure, hydrocarbon shows and reservoir potential in three separate horizons; however, results from three attempts to drill stem test the well prior to releasing the drilling rig were inconclusive.



NE british columbia



- World-class production and reserves
- Several high impact plays identified
- Deep multi-zone natural gas targets
- High risk operations

Crown lands offsetting the Adsett well were acquired by the Company and partners in January of 2004. Due to equipment shortages at the time, the farmee operator was unable to secure a service rig capable of well completion and testing until late January. Completion activities on the Slave Point/Sulphur Point formations continued for several weeks in February resulting in strong indications of natural gas flow and significant associated water. As a result of these production tests, the farmee operator elected to plug back the well and complete and test the shallower Debolt zone, which resulted in indications of a low permeability reservoir. The well was subsequently abandoned. Virtus will evaluate a further up-hole horizon, which it expects will lead to additional winter drilling in 2004 either through farmout or direct participation. Drilling results from this well have shown evidence of hydrocarbon accumulations in three horizons, all of which will likely require the acquisition of additional 3-D seismic data to further define the potential of the structure.

TENAKA, BRITISH COLUMBIA

At the September 2003 Crown land sale, Virtus and its original partners in the Adsett lands successfully acquired four gas spacing units of undeveloped lands in the Tenaka area, which is approximately 25 kilometres from the Adsett prospect. Indications of significant structure on the Tenaka lands were evident on airborne survey data acquired by a joint venture partner prior to the Crown land sale. Based on that data, Virtus and partners acquired the lands for $700,000 and subsequently acquired seismic data to confirm the structure. Virtus is the operator with a 33.34% working interest. During 2004, the Company expects additional seismic will be acquired on the prospect and a third party farmin partner will be secured.

Medium Risk Prospects

Virtus is developing a new focus area in northeast British Columbia, pursuing multi-zone bypassed pay opportunities to complement the Company's high impact prospects.

FORT ST. JOHN EXPLORATION

Late in 2003, Virtus began exploration initiatives in the Fort St. John area of northeastern British Columbia. With a strong technical team focused on the area, the Company expects to pursue up to ten prospects in this region during 2004. By the end of the first quarter, Virtus had acquired lands on five separate prospects: the Stoddart and Aitken Creek plays are two of these new projects in this emerging focus area.

STODDART, BRITISH COLUMBIA

In late 2003, Virtus acquired two key tracts of undeveloped land for bypassed oil and gas potential in the Stoddart area of British Columbia. A farmin partner has been secured and the initial well has been drilled and is awaiting completion in the second quarter of 2004. If successful, up to three contingent follow-up locations are planned.

AITKEN CREEK, BRITISH COLUMBIA

In the Aitken Creek area located northwest of Fort St. John, Virtus and an industry partner acquired 3,525 gross (2,485 net) acres of undeveloped lands at recent Crown sales. Virtus has obtained a joint venture partner for the initial test well on this geophysically supported prospect, which is expected to commence drilling in the third quarter of 2004. This Virtus operated well will test six prospective zones for natural gas potential.

optimizing

At year-end, Virtus had total proved reserves of 1,178,747 gross boes giving a reserve life of over five years. We replaced 150% of production through an aggressive acquisition and optimization plan and expect to add new reserves by way of focused exploration and additional opportunistic acquisitions.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Corporate governance

Sound corporate governance practices, which are the responsibility of the Company's Board of Directors and its associated committees, are designed to facilitate the development of Virtus and the enhancement of value for all shareholders. The Board believes sound corporate governance benefits the shareholders, management and employees of the Company and the communities in which it operates.

1. **The Board should assume responsibility for the stewardship of the Corporation, specifically, adoption of a strategic planning process, identification of principal risks, succession planning and monitoring of management, a communications policy, and the integrity of internal control and management information systems.**

   Management is responsible for developing the overall corporate strategies. These strategies are presented to, reviewed and approved by the Board. The Board and management identify the principal risks of the business and have established processes and programs to manage those risks to protect shareholder value. The Compensation Committee is responsible for ensuring management is qualified and has the appropriate expertise to manage the day-to-day operations of the business. The Board is consulted with respect to corporate communications. The Company has established a communication policy, which provides timely dissemination of information to shareholders, other stakeholders and the general public. The Audit and Reserves Committee is responsible for establishing an appropriate system of financial controls and policies to ensure the timely and accurate reporting of information.

2. **A majority of the Board should be unrelated directors.**

   The Board presently consists of five directors, of which four are unrelated.

3. **Disclosure for each director as to whether related or unrelated and the basis for the conclusion reached.**

   Peter A. Carwardine is a related director due to his role as President and Chief Executive Officer of the Company. The remaining four directors are unrelated as they are neither part of management nor a significant shareholder individually with the ability to exercise a majority of votes for the election of directors.

4. **A committee of unrelated directors responsible for proposing new Board members and evaluating current directors.**

   The Board of Directors does not have a separate committee to propose new Board members or evaluate current directors. All members of the Board have the right to propose new Board members, and all directors have input in assessing directors on an ongoing basis.

5. **Implement a process to assess the effectiveness of the Board, its committees and individual directors.**

   There is no formal process to assess the effectiveness of the Board, its committees and directors. The Board as a whole is responsible for providing input as to the performance and effectiveness of the committees and individual directors.

6. **Provide orientation and education to new directors.**

   New directors receive orientation on an informal basis upon joining the Board. All directors have access to any of the Company's employees to learn more about the Company's business. No formal education program is provided as new directors are chosen based upon their knowledge of the Company's business and industry and past experience as directors.

7. **Evaluate the size of the Board to ensure it facilitates effective decision-making.**

   The Board believes that five members is appropriate to facilitate effective decision-making and fulfill the responsibilities of the various Board committees.

8. **Review the compensation for the directors to ensure it reflects the risks and responsibilities.**

   The Compensation Committee of the Board is responsible for reviewing the remuneration of the directors.

9. **Committees of the Board should generally be composed of unrelated directors.**

   All of the committees of the Board are comprised of a majority of unrelated directors. The Audit and Reserves Committee is comprised entirely of unrelated directors.

10. **The Board, or a committee of the Board, should expressly assume the responsibility for developing an approach to governance issues.**

    The Board believes that developing and monitoring the Company's approach to corporate governance issues is the responsibility of all directors.

11. **The Board with the Chief Executive Officer (CEO) should develop position descriptions for the directors, and the CEO and the Board should approve or develop corporate objectives, which the CEO is responsible for meeting.**

    The Board's role is to oversee the management of the Company's business and strategies, and monitor and assess management's conduct and performance. The CEO reports to the Board and is responsible for the day-to-day operations of the Company. The Board is responsible for reviewing and approving the annual budget establishing the objectives the CEO is responsible for achieving.

12. **Ensure the Board can function independent of management.**

    The Board has ensured it can function independently of management by appointing an unrelated director as Chairman of the Board and ensuring committees of the Board consist of a majority of unrelated directors.

13. **The Audit Committee's roles and responsibilities should be clearly defined and the Committee should be comprised of unrelated directors.**

    The Audit and Reserves Committee is responsible for establishing appropriate financial controls and policies, reviewing the quarterly and annual financial statements and related disclosure, and the performance of the independent auditors. The Committee is also responsible for reviewing the qualifications of and process used by the Company's independent engineering firm in preparing the annual reserves evaluation report. The Audit and Reserves Committee is comprised entirely of unrelated directors.

14. **Implement a system to enable directors to engage outside advisors at the Company's expense.**

    The Board or any of the directors may engage outside advisors at the expense of the Company when appropriate.

BOARD OF DIRECTORS STEWARDSHIP

The Board considers certain decisions to be sufficiently important that management is required to seek prior approval of the Board. Such decisions include:

1. The annual capital and operating budget and any material changes to the budget;
2. The acquisition or disposition of any significant oil and natural gas assets;
3. Significant commitments with industry partners;
4. Entering into forward pricing arrangements;
5. Equity or debt financings;
6. Changes to the management group; and
7. Significant changes in corporate policies, goals or objectives.

The Board of Directors meet at least once in each quarter and otherwise as needed.

INSIDER TRADING GUIDELINES

The Company has established guidelines that state there will be a trading black out for employees, management and directors from the point in time quarterly financial statements are released to the Board of Directors until the press release is issued. The Company also has the discretion to issue a trading black out for employees, management and directors when material issues or transactions warrant.

Management's discussion and analysis

The following discussion and analysis has been prepared by management, and reviewed and approved by the Board of Directors of Virtus Energy Ltd. The discussion and analysis is a review of the operational results of the Company with disclosure of oil and gas activities in accordance with Canadian Securities Regulators National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities (NI 51-101) and a review of financial results of the Company based upon accounting principles generally accepted in Canada. Its focus is primarily a comparison of the operational and financial performance for the years ended December 31, 2003 and 2002 and should be read in conjunction with the audited financial statements and accompanying notes. The discussion and analysis has been prepared as of March 25, 2004.

For the purpose of calculating unit costs, natural gas volumes have been converted to a barrel equivalent (boe) using six thousand cubic feet equal to one barrel unless otherwise stated. A boe conversion ratio of 6:1 is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion conforms with NI 51-101. Boes may be misleading, particularly if used in isolation.

Cash flow from operations is not a recognized measure under Canadian generally accepted accounting principles. Management believes that cash flow from operations is a useful measure of financial performance. For the purposes of cash flow from operations calculations, cash flow is defined as "Cash flow from operating activities" before changes in non-cash operating working capital. The Company also presents cash flow from operations per share whereby amounts per share are calculated using weighted average shares outstanding consistent with the calculation of earnings per share. Cash flow from operations and funds from operations as noted in the financial statements are terms that are used synonymously.

Forward-Looking Statements. Certain information regarding Virtus Energy Ltd. set forth in this document, including management's assessment of the Company's future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond the Company's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other oil and gas companies, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from both internal and external sources. The Company's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements, and accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur. The Company assumes no obligation to publicly update or revise any forward-looking information.

Operational Review and Analysis

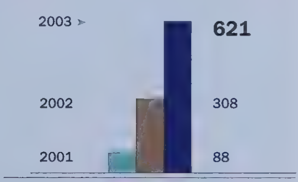
LAND HOLDINGS

During 2003, Virtus was an active participant at Crown land sales throughout Western Canada spending $611,475. Successful purchases in Alberta as well as Tenaka and Stoddart in northeastern British Columbia resulted in additions of 4,235 net acres. The expiry of undeveloped lands at Merryflats in southwestern Saskatchewan and the sale of the Company's assets at Golden Spike in central Alberta resulted in a reduction of 19,060 net acres. As a consequence, Virtus' undeveloped land holdings at December 31, 2003 were reduced to 29,295 net acres, while total land holdings amounted to 75,408 gross (37,672 net) acres compared to 88,674 gross (52,134 net) acres a year ago.

	2003			2002		
	GROSS	NET	AVERAGE INTEREST	GROSS	NET	AVERAGE INTEREST
	acres	acres	%	acres	acres	%
Developed lands						
Alberta	**20,094**	**5,603**	**27.9**	24,987	6,457	25.8
Saskatchewan	**3,413**	**2,694**	**78.9**	1,477	1,477	100.0
British Columbia	**643**	**80**	**12.4**	643	80	12.4
Total	**24,150**	**8,377**	**34.7**	27,107	8,014	29.6
Undeveloped lands						
Alberta	**23,172**	**11,067**	**47.8**	22,414	11,595	51.7
Saskatchewan	**15,796**	**13,252**	**83.9**	30,918	29,780	96.3
British Columbia	**12,290**	**4,976**	**40.4**	8,235	2,745	33.4
Total	**51,258**	**29,295**	**57.2**	61,567	44,120	71.7
Total lands						
Alberta	**43,266**	**16,670**	**38.5**	47,401	18,052	38.1
Saskatchewan	**19,209**	**15,946**	**83.0**	32,395	31,257	96.5
British Columbia	**12,933**	**5,056**	**39.1**	8,878	2,825	31.8
Total	**75,408**	**37,672**	**50.0**	88,674	52,134	58.8

PRODUCTION

Production for the year averaged 621 boe/d compared to 308 boe/d in 2002. This 102% increase was due to improved oil and natural gas production, which was up 72% and 498%, respectively, over the prior year. Increased oil production was primarily a result of the acquisition made at Seal, Alberta in April of 2003 of approximately 230 bbls/d, with additional volume increases from optimization and recompletion operations undertaken in that area throughout the remainder of the year. Increased natural gas production was due to the purchase of 400 mcf/d and a successful recompletion at Seal, completing tie-in operations of natural gas reserves at Battle Creek, Saskatchewan and successful drilling at Wildwood, Alberta. The Company's 2003 exit production rate was approximately 750 boe/d versus 400 boe/d a year ago.



Production
(boe/d)

	2003	2002
Oil (bbls/d)	**483**	281
Natural gas (mcf/d)	**789**	132
NGLs (bbls/d)	**6**	5
Total (boe/d)	**621**	308

DRILLING ACTIVITY

In 2003, Virtus participated in the drilling of 9 gross (3.7 net) wells and recorded an average working interest of 41%. The Company drilled a successful light oil exploration well at Seal, Alberta, a natural gas exploration well at Wildwood, Alberta and a successful shallow natural

gas well at Battle Creek, Saskatchewan. A southwest Saskatchewan drilling program resulted in one natural gas success, which has been cased, and one dry hole. A step-out development well at Wildwood and exploration wells at Seal and Spirit River, Alberta as well as Adsett, British Columbia were dry and abandoned. Drilling plans for 2004 call for 10 gross wells at an average working interest of 60%. The Company plans to operate approximately 90% of its drilling program during 2004.

	EXPLORATION		DEVELOPMENT		TOTAL	
	GROSS	NET	GROSS	NET	GROSS	NET
	#	#	#	#	#	#
2003						
Oil	1.0	0.6	–	–	1.0	0.6
Natural gas	2.0	0.8	1.0	0.6	3.0	1.4
Dry & abandoned	4.0	1.5	1.0	0.2	5.0	1.7
Total wells	7.0	2.9	2.0	0.8	9.0	3.7
Success rate (%)	43	–	50	–	44	–
Average capital working interest (%)	–	41	–	40	–	41
2002						
Oil	1.0	0.6	1.0	1.0	2.0	1.6
Natural gas	–	–	3.0	3.0	3.0	3.0
Dry & abandoned	1.0	1.0	1.0	1.0	2.0	2.0
Total wells	2.0	1.6	5.0	5.0	7.0	6.6
Success rate (%)	50	–	80	–	71	–
Average capital working interest (%)	–	80	–	100	–	94

RESERVES

In a report dated March 8, 2004, Gilbert Laustsen Jung Associates Ltd. (GLJ), an independent petroleum engineering firm, evaluated the crude oil, natural gas liquids and natural gas reserves of the Company as at December 31, 2003. GLJ based their evaluation on land data, well and geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts and future operating plans provided by Virtus, and prepared their report in accordance with NI 51-101. The required disclosure of the reserve estimates and future net revenue of the Company as at December 31, 2003 based upon forecast prices and costs, followed by similar information based upon constant prices and costs, are outlined below along with the economic assumptions used in preparing those estimates.

Forecast Prices and Costs

SUMMARY OF OIL AND GAS RESERVES

The following table outlines the oil and gas reserves of the Company by product type on a gross (before royalties) and net (after royalties) basis. At December 31, 2003, the Company had 1,178,747 gross (991,046 net) proved boes and 1,466,796 gross (1,235,096 net) proved plus probable boes.

	LIGHT & MEDIUM OIL		NATURAL GAS		NGLS	
	GROSS	NET	GROSS	NET	GROSS	NET
	bbls	bbls	mcf	mcf	bbls	bbls
Proved						
Developed producing	801,007	679,299	1,218,184	982,818	10,787	7,713
Developed non-producing	20,133	15,459	203,076	174,336	–	–
Undeveloped	105,670	92,724	25,641	17,949	–	–
Total proved	926,810	787,482	1,446,901	1,175,103	10,787	7,713
Probable	191,075	166,422	557,561	448,578	4,047	2,865
Total proved plus probable	1,117,885	953,904	2,004,462	1,623,681	14,834	10,578

RECONCILIATION OF COMPANY NET RESERVES BY PRINCIPAL PRODUCT

The reconciliation of the Company's net proved, probable and proved plus probable reserves for December 31, 2003 is as follows:

	LIGHT & MEDIUM OIL			NATURAL GAS			NGLS		
	NET PROVED	NET PROBABLE	NET PROVED PLUS PROBABLE	NET PROVED	NET PROBABLE	NET PROVED PLUS PROBABLE	NET PROVED	NET PROBABLE	NET PROVED PLUS PROBABLE
	bbls	bbls	bbls	mcf	mcf	mcf	bbls	bbls	bbls
December 31, 2002	639,402	156,496	795,898	1,622,000	1,282,000	2,904,000	12,595	16,585	29,180
NI 51-101	–	(78,248)	(78,248)	–	(641,000)	(641,000)	–	(8,293)	(8,293)
Extensions	–	–	–	–	109,000	109,000	8,000	3,000	11,000
Improved recovery	128,000	–	128,000	97,000	–	97,000	–	–	–
Technical revisions	(23,602)	12,174	(11,428)	(330,885)	(86,422)	(417,307)	1,342	5,573	6,915
Discoveries	–	–	–	341,000	129,000	470,000	–	–	–
Acquisitions	294,000	100,000	394,000	442,000	143,000	585,000	–	–	–
Dispositions	(60,000)	(16,000)	(76,000)	(636,000)	(491,000)	(1,127,000)	(12,000)	(14,000)	(26,000)
Economic factors	(14,000)	(8,000)	(22,000)	(72,000)	4,000	(68,000)	–	–	–
Production	(176,318)	–	(176,318)	(288,012)	–	(288,012)	(2,224)	–	(2,224)
December 31, 2003	787,482	166,422	953,904	1,175,103	448,578	1,623,681	7,713	2,865	10,578

NET PRESENT VALUES OF FUTURE NET REVENUE

The net present values of future net revenue of the Company's reserves at various discount rates on a before and after tax basis are outlined below. At December 31, 2003, the Company had approximately $17,235,841 of tax deductions available to reduce future taxable income, and as a result, the reduction to the net present values for future income taxes is approximately 14%.

	BEFORE INCOME TAXES DISCOUNTED AT				
	0%	5%	10%	15%	20%
	$	$	$	$	$
Proved					
Developed producing	12,958,000	11,895,000	11,017,000	10,281,000	9,655,000
Developed non-producing	505,000	418,000	352,000	301,000	261,000
Undeveloped	1,488,000	1,236,000	1,040,000	885,000	761,000
Total proved	14,951,000	13,549,000	12,409,000	11,467,000	10,677,000
Probable	4,002,000	3,199,000	2,628,000	2,205,000	1,883,000
Total proved plus probable	18,953,000	16,748,000	15,037,000	13,672,000	12,560,000

	AFTER INCOME TAXES DISCOUNTED AT				
	0%	5%	10%	15%	20%
	$	$	$	$	$
Proved					
Developed producing	11,920,000	10,896,000	10,054,000	9,351,000	8,755,000
Developed non-producing	372,000	295,000	237,000	192,000	158,000
Undeveloped	1,097,000	871,000	700,000	566,000	460,000
Total proved	13,389,000	12,062,000	10,991,000	10,109,000	9,373,000
Probable	3,172,000	2,471,000	1,981,000	1,627,000	1,361,000
Total proved plus probable	16,561,000	14,533,000	12,972,000	11,736,000	10,734,000

TOTAL FUTURE NET REVENUE

The following table provides a breakdown of the various components of total future net revenue on an undiscounted basis for proved and proved plus probable reserves:

	REVENUE	ROYALTIES	OPERATING COSTS	DEVELOPMENT COSTS	WELL ABANDONMENT COSTS	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
(000s)	$	$	$	$	$	$	$	$
Proved								
2004	10,167	1,585	2,403	951	40	5,188	915	4,273
2005	7,060	983	2,257	113	25	3,682	478	3,204
2006	4,999	634	1,979	–	22	2,364	142	2,222
2007	3,938	459	1,760	91	49	1,579	27	1,552
2008	2,905	331	1,432	–	97	1,045	–	1,045
2009	2,103	234	1,186	–	146	537	–	537
2010	1,362	158	820	–	70	314	–	314
2011	962	119	639	–	43	161	–	161
2012	654	77	475	–	87	15	–	15
2013	57	1	25	–	25	6	–	6
Remainder	206	–	105	–	41	60	–	60
	34,413	4,581	13,081	1,155	645	14,951	1,562	13,389
Proved plus probable								
2004	10,460	1,667	2,408	1,044	40	5,301	992	4,309
2005	7,839	1,138	2,324	113	5	4,259	690	3,569
2006	5,846	771	2,119	–	41	2,915	338	2,577
2007	4,678	573	1,863	91	16	2,135	219	1,916
2008	3,831	442	1,741	–	72	1,576	114	1,462
2009	2,934	335	1,423	–	84	1,092	39	1,053
2010	2,307	250	1,270	–	81	706	–	706
2011	1,702	183	1,023	–	52	444	–	444
2012	1,183	137	771	–	102	173	–	173
2013	826	92	562	–	46	126	–	126
Remainder	1,021	29	637	–	129	226	–	226
	42,627	5,617	16,141	1,248	668	18,953	2,392	16,561

FUTURE NET REVENUE BY PRODUCT

On a product basis, future net revenue of the Company consists of light and medium crude oil and natural gas, with 78% of the future net revenue represented by light and medium crude oil on a proved reserve basis and 78% on a proved plus probable basis.

	PRODUCT	FUTURE NET REVENUE BEFORE INCOME TAXES (DISCOUNTED AT 10%)
		$
Proved	Light & medium crude oil	9,702,000
	Natural gas	2,108,000
	ARTC	599,000
		12,409,000
Proved plus probable	Light & medium crude oil	11,720,000
	Natural gas	2,605,000
	ARTC	712,000
		15,037,000

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS

The economic parameters, as determined by GLJ, assumed in preparing the forecast prices and costs reserves report are as follows:

				OIL	NATURAL GAS		
YEAR	WTI CUSHING OKLAHOMA	EDMONTON PAR PRICE 40° API	HARDISTY HEAVY 12° API	CROMER MEDIUM 29° API	AECO GAS PRICE	INFLATION RATE	EXCHANGE RATE
	US$/bbl	CDN$/bbl	CDN$/bbl	CDN$/bbl	CDN$/mmbtu	%/year	US$/CDN$
Historical							
2000	30.22	44.56	27.34	39.91	5.08	2.7	0.674
2001	25.97	39.40	16.94	31.56	6.21	2.6	0.645
2002	26.08	40.33	26.57	35.48	4.04	2.2	0.638
2003	30.96	43.51	26.01	37.26	6.66	2.8	0.721
Forecast							
2004	29.00	37.75	20.25	31.75	5.85	1.5	0.75
2005	26.00	33.75	20.25	28.75	5.15	1.5	0.75
2006	25.00	32.50	21.00	28.50	5.00	1.5	0.75
2007	25.00	32.50	21.00	28.50	5.00	1.5	0.75
2008	25.00	32.50	21.00	28.50	5.00	1.5	0.75
2009	25.00	32.50	21.00	28.50	5.00	1.5	0.75
2010	25.00	32.50	21.00	28.50	5.00	1.5	0.75
2011	25.00	32.50	21.00	28.50	5.00	1.5	0.75
2012	25.00	32.50	21.00	28.50	5.00	1.5	0.75
2013	25.00	32.50	21.00	28.50	5.00	1.5	0.75
2014	25.00	32.50	21.00	28.50	5.00	1.5	0.75
Thereafter	1.5%/yr	1.5%/yr	1.5%/yr	1.5%/yr	1.5%/yr	1.5	0.75

Constant Prices and Costs

SUMMARY OF OIL AND GAS RESERVES

The following table outlines the oil and gas reserves of the Company by product type using constant price and cost assumptions on a gross (before royalties) and net (after royalties) basis. The constant price and cost scenarios have slightly higher oil and natural gas reserves compared to the forecast reserves. The increase is due to high December 31, 2003 prices for both commodities being held constant compared to the declining forecast pricing assumptions.

	LIGHT & MEDIUM OIL		NATURAL GAS		NGLS	
	GROSS	NET	GROSS	NET	GROSS	NET
	bbls	bbls	mcf	mcf	bbls	bbls
Proved						
Developed producing	866,367	734,167	1,241,000	1,002,000	11,194	7,940
Developed non-producing	24,095	19,108	203,076	174,227	–	–
Undeveloped	103,100	89,193	24,934	17,454	–	–
Total proved	993,562	842,468	1,469,010	1,193,681	11,194	7,940
Probable	216,294	187,930	563,433	452,419	4,082	2,860
Total proved plus probable	1,209,856	1,030,398	2,032,443	1,646,100	15,276	10,800

NET PRESENT VALUES OF FUTURE NET REVENUE

The net present values of future net revenue of the Company's reserves at various discount rates on a before and after tax basis are as follows:

	BEFORE INCOME TAXES DISCOUNTED AT				
	0%	5%	10%	15%	20%
	$	$	$	$	$
Proved					
Developed producing	18,912,000	16,882,000	15,283,000	13,995,000	12,935,000
Developed non-producing	787,000	655,000	557,000	482,000	422,000
Undeveloped	2,182,000	1,816,000	1,535,000	1,312,000	1,135,000
Total proved	21,881,000	19,353,000	17,375,000	15,789,000	14,492,000
Probable	6,211,000	4,770,000	3,792,000	3,100,000	2,593,000
Total proved plus probable	28,092,000	24,123,000	21,167,000	18,889,000	17,085,000

	AFTER INCOME TAXES DISCOUNTED AT				
	0%	5%	10%	15%	20%
	$	$	$	$	$
Proved					
Developed producing	16,522,000	14,665,000	13,213,000	12,051,000	11,102,000
Developed non-producing	523,000	419,000	344,000	286,000	241,000
Undeveloped	1,449,000	1,163,000	947,000	780,000	649,000
Total proved	18,494,000	16,247,000	14,504,000	13,117,000	11,992,000
Probable	4,449,000	3,325,000	2,585,000	2,076,000	1,709,000
Total proved plus probable	22,943,000	19,572,000	17,089,000	15,193,000	13,701,000

RECONCILIATION OF CHANGES IN NET PRESENT VALUES OF FUTURE NET REVENUE DISCOUNTED AT 10% – PROVED RESERVES

The following table provides a detailed reconciliation of the change in net present values of proved reserves using constant prices and costs:

	2003
	$
Estimated future net revenue, beginning of year	**14,162,000**
Sales & transfers of oil & gas produced, net of production costs & royalties	**(4,226,000)**
Net changes in prices, production costs & royalties related to future production	**(8,563,000)**
Changes in previously estimated development costs incurred during the period	**1,007,000**
Extensions & improved recovery	**2,516,000**
Discoveries	**973,000**
Acquisitions of reserves	**6,074,000**
Disposition of reserves	**(3,030,000)**
Net change resulting from revisions in quantity estimates	**(1,835,000)**
Accretion of discount	**1,811,000**
Net change in income taxes	**1,076,000**
Other	**4,539,000**
Estimated future net revenue, end of year	**14,504,000**

TOTAL FUTURE NET REVENUE

The following table provides a breakdown of the various components of total future net revenue on an undiscounted basis for proved reserves using constant prices and costs:

	REVENUE	ROYALTIES	OPERATING COSTS	DEVELOP-MENT COSTS	WELL ABANDON-MENT COSTS	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
(000s)	$	$	$	$	$	$	$	$
Proved								
2004	11,000	1,749	2,408	951	40	5,852	1,172	4,680
2005	8,639	1,255	2,227	111	13	5,033	984	4,049
2006	6,378	840	1,953	–	32	3,553	575	2,978
2007	5,003	609	1,685	88	27	2,594	387	2,207
2008	3,756	442	1,398	–	91	1,825	208	1,617
2009	2,724	312	1,149	–	100	1,163	62	1,101
2010	1,975	233	921	–	48	773	–	773
2011	1,423	178	706	–	38	501	–	501
2012	1,112	137	611	–	54	310	–	310
2013	569	46	361	–	53	109	–	109
Remainder	1,216	57	895	–	95	169	–	169
	43,795	5,858	14,314	1,150	591	21,882	3,388	18,494

FUTURE NET REVENUE BY PRODUCT

On a product basis, 78% of the future net revenue was represented by light and medium crude oil on a proved reserve basis and 78% on a proved plus probable basis.

	PRODUCT	FUTURE NET REVENUE BEFORE INCOME TAXES (DISCOUNTED AT 10%)
		$
Proved	Light & medium crude oil	13,500,000
	Natural gas	3,152,000
	ARTC	723,000
		17,375,000
Proved plus probable	Light & medium crude oil	16,435,000
	Natural gas	3,865,000
	ARTC	867,000
		21,167,000

SUMMARY OF PRICING ASSUMPTIONS

The historical and December 2003 economic parameters assumed in preparing the constant prices and costs reserves report are as follows:

				OIL	NATURAL GAS	
YEAR	WTI CUSHING OKLAHOMA	EDMONTON PAR PRICE 40° API	HARDISTY HEAVY 12° API	CROMER MEDIUM 29° API	AECO GAS PRICE	EXCHANGE RATE
	US$/bbl	CDN$/bbl	CDN$/bbl	CDN$/bbl	CDN$/mmbtu	US$/CDN$
Historical (average)						
2000	30.22	44.56	27.34	39.91	5.08	0.674
2001	25.97	39.40	16.94	31.56	6.21	0.645
2002	26.08	40.33	26.57	35.48	4.04	0.638
2003	30.96	43.51	26.01	37.26	6.66	0.721
2003 (December)	32.52	40.81	23.31	34.81	6.09	0.774

INVESTMENT EFFICIENCY

The following reserve statistics and ratios have been determined based upon the summary of oil and gas reserves using forecast prices and costs.

RESERVE LIFE INDEX

The reserve life index of Virtus has been calculated using 2003 production volumes and gross proved and proved plus probable reserves using forecast prices and costs. The reserve life index of the Company as at December 31, 2003, on a boe basis, is 5.2 years for proved reserves and 6.5 using proved plus probable reserves.

	2003 PRODUCTION	PROVED	PROVED PLUS PROBABLE
		years	years
Oil (bbls)	**176,318**	5.3	6.3
Natural gas (mcf)	**288,012**	5.0	7.0
NGLs (bbls)	**2,224**	4.9	6.7
Total (boe)	**226,544**	5.2	6.5

FINDING AND DEVELOPMENT COSTS

The finding and development costs for 2001, 2002, 2003 and a three-year average are outlined below for proved reserve additions. In accordance with NI 51-101, the finding and development calculations include the change in future development costs.

	2001	2002	2003	3-YEAR AVERAGE
	$	$	$	$
Proved				
Capital expenditures	809,087	4,672,874	**6,583,480**	12,065,441
Future development capital	208,000	590,000	**98,000**	896,000
Total	1,017,087	5,262,874	**6,681,480**	12,961,441
Reserve additions (boe)	(72,561)	195,705	**120,636**	243,780
Finding & development costs ($/boe)	–	26.89	**55.39**	53.17

Including the capital expenditures for acquisitions and proceeds on the disposition of property and equipment would result in finding and development costs as outlined in the following table:

	2001	2002	2003	3-YEAR AVERAGE
	$	$	$	$
Proved				
Capital expenditures	809,087	4,672,874	**6,583,480**	12,065,441
Acquisition capital	3,669,385	1,827,800	**5,903,148**	11,400,333
Proceeds on disposition	–	(353,722)	**(1,972,030)**	(2,325,752)
Future development capital	208,000	590,000	**98,000**	896,000
Total	4,686,472	6,736,952	**10,612,598**	22,036,022
Reserve additions (boe)	(72,561)	195,705	**120,636**	243,780
Reserves acquired (boe)	381,967	414,908	**436,667**	1,233,542
Reserves disposed of (boe)	–	(43,474)	**(217,380)**	(260,854)
Total (boe)	309,406	567,139	**339,923**	1,216,468
Finding & development costs ($/boe)	15.15	11.88	**31.22**	18.11

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions.

Financial Review and Analysis

Quarterly Information

The operational and financial results of Virtus over the past eight quarters are highlighted by an increase in capital programs, steady growth in production volumes and continuous improvement in cash flow from operations. During 2001, the Company initiated a reorganization and recapitalization process that included recruiting a new management team and Board of Directors, issuing equity to strengthen the balance sheet and pursuing an active capital expenditures program through acquisitions and drilling operations.

Over the eight-quarter period, the Company's primary focus has been on establishing a base level of production from which it can pursue an active drilling program. Capital expenditures increased from $250,441 in the first quarter of 2002 to $2,843,732 in the fourth quarter of 2003 with an increased percentage of capital expenditures being directed towards drilling operations. Capital expenditures reached $6,625,222 in the second quarter of 2003, resulting from the acquisition of producing oil and natural gas properties and operated facilities at Seal, Alberta.

Production volumes per day, as a result of the expanding capital program, have increased from an average 193 boe/d in the first quarter of 2002 to an average 783 boe/d in the fourth quarter of 2003. Oil production increased 203% from 182 bbls/d in the first quarter of 2002 to 552 bbls/d in the fourth quarter of 2003 while natural gas production improved 1,873% from 67 mcf/d in the first quarter of 2002 to 1,322 mcf/d in the fourth quarter of 2003.

The steady increase in production volumes in combination with strong, but volatile, commodity prices over the past two years produced significant growth in quarterly operating cash flow. Cash flow from operations increased 1,488% from $47,555 in the first quarter of 2002 to $755,343 in the fourth quarter of 2003.

The Company's capital programs have been financed by a combination of internally generated cash flow from operations, proceeds from the disposition of non-core assets, equity financings and bank debt. During the past two years, the Company issued 21,200,000 common shares and raised $11,046,000 in three private placements of common and flow-through common shares. At the end of the fourth quarter of 2003, the Company had outstanding bank debt of $2,075,000 and a working capital deficit of $2,234,369.

The following table sets forth certain quarterly information of the Company for the last two fiscal years:

	Q1	Q2	Q3	Q4	TOTAL
	$	$	$	$	$
2003					
Production					
Oil (bbls/d)	362	540	477	552	**483**
Natural gas (mcf/d)	147	614	1,057	1,322	**789**
NGLs (bbls/d)	5	5	4	11	**6**
Total (boe/d)	391	647	657	783	**621**
Petroleum & natural gas sales	1,254,477	2,121,366	2,068,208	2,425,999	**7,870,050**
Cash flow from operations	315,921	797,076	855,753	755,343	**2,724,093**
Per share - basic	0.01	0.03	0.02	0.02	**0.08**
Per share - diluted	0.01	0.03	0.02	0.02	**0.08**
Net earnings (loss)	(48,256)	51,220	(10,556)	(230,911)	**(238,503)**
Per share - basic	–	–	–	(0.01)	**(0.01)**
Per share - diluted	–	–	–	(0.01)	**(0.01)**
Capital expenditures	1,124,657	6,625,222	1,967,086	2,843,732	**12,560,697**
Bank debt	–	4,215,000	1,050,000	2,075,000	**2,075,000**
Working capital (surplus) deficit	502,344	176,029	1,198,217	2,234,369	**2,234,369**
Shareholders' equity	10,375,621	10,677,120	13,753,216	13,141,292	**13,141,292**
2002					
Production					
Oil (bbls/d)	182	230	332	379	281
Natural gas (mcf/d)	67	149	136	176	132
NGLs (bbls/d)	–	6	6	6	5
Total (boe/d)	193	261	361	414	308
Petroleum & natural gas sales	483,025	787,688	1,133,414	1,233,477	3,637,604
Cash flow from operations	47,555	220,339	300,839	267,201	835,934
Per share - basic	–	0.01	0.01	0.01	0.04
Per share - diluted	–	0.01	0.01	0.01	0.04
Net earnings (loss)	(76,877)	1,911	(58,708)	(81,176)	(214,850)
Per share - basic	(0.01)	–	–	–	(0.01)
Per share - diluted	(0.01)	–	–	–	(0.01)
Capital expenditures	250,441	2,364,321	1,938,222	1,992,570	6,545,554
Bank debt	–	450,000	1,000,000	–	–
Working capital (surplus) deficit	(958,222)	547,599	1,654,450	(309,859)	(309,859)
Shareholders' equity	6,874,037	6,663,493	6,296,225	10,632,805	10,632,805

2003 FOURTH QUARTER

Virtus continued to increase its production in the fourth quarter of 2003. Oil production increased to 552 bbls/d from the year's third quarter average of 477 bbls/d. This 16% increase was due to additional production at Seal, Alberta as a result of optimization work done on numerous wells. Natural gas production increased to 1,322 mcf/d in the fourth quarter from third quarter production of 1,057 mcf/d. This 25% improvement was due to increased production at Seal and Wildwood, Alberta. Average production for the fourth quarter increased 19% to 783 boe/d versus 657 boe/d in the third quarter.

While benchmark crude oil prices continued to strengthen in the fourth quarter, Canadian crude oil prices, albeit still very strong, were adversely impacted by the strengthening CDN/US dollar foreign exchange rate. The Canadian dollar improved from CDN/US$1.3801 in the third quarter to CND/US$1.3157 in the fourth quarter. Consequently, the Company's realized oil price in the fourth quarter of $31.64/bbl, after net settlement payments on hedging, was 6% lower than the third quarter's $33.61/bbl. Quarter-over-quarter realized natural gas prices remained virtually unchanged at $5.93/mcf.

Petroleum and natural gas sales increased 17% to $2,425,999 in the fourth quarter compared to $2,068,208 in the third quarter of 2003. This improvement was primarily due to increased crude oil and natural gas production offset by lower realized crude oil prices.

Royalties, net of ARTC, were $421,112 in the fourth quarter versus $302,859 the previous quarter. Royalties as a percentage of sales increased to 17.4% in the fourth quarter, up from 14.6% of sales in the third quarter due to royalty holidays ending on several wells and higher royalty rates on other wells as a result of increased productivity.

Production expenses were $717,515 in the fourth quarter compared to $648,029 in the third quarter of 2003. This 11% increase reflects the additional costs incurred as a result of higher production volumes. Operating costs in the fourth quarter totaled $9.96/boe versus $10.72/boe in the third quarter, a 7% decrease.

General and administrative expenses were $427,115 in the three months ended December 31, 2003 compared to $227,060 in the three months ended September 30, 2003. The quarter-over-quarter increase was due to the Company's participation in several investor conferences and increased professional fees associated with year-end reporting requirements.

Interest expense in the fourth quarter was $38,228 versus $52,034 in the third quarter. Average bank debt balances were approximately the same in each period, however, lower prime lending rates and a reduced credit spread on the Company's bank debt resulted in this decrease in interest expense.

Depletion and depreciation in the fourth quarter was $1,063,668 compared to $786,072 in the third quarter of 2003. This 35% increase is a result of improved production volumes and a higher depletion rate per boe. Depletion and depreciation in the fourth quarter was $14.77/boe versus $13.01/boe in the third quarter of 2003.

The Company incurred a net loss of $230,911 in the fourth quarter compared to a net loss of $10,556 in the third quarter of 2003. Cash flow from operations in the fourth quarter was $755,343 ($0.02 per share) compared to $855,753 ($0.02 per share) in the third quarter.

Capital expenditures were $2,843,732 in the fourth quarter. Operations were primarily directed at Seal, Alberta with facility upgrades and optimization activities as well as drilling two exploration and two development wells in various other areas. The following table provides a breakdown of capital incurred in the fourth quarter:

	Q4 - 2003
	$
Land	243,250
Geological & geophysical	119,618
Drilling & completions	1,153,599
Production equipment	1,387,642
Acquisition of properties & equipment	(89,812)
Office furniture & equipment	29,435
	2,843,732

Annual Information

COMMODITY PRICES

	2003	2002
	$	$
Crude oil		
West Texas Intermediate (US$/bbl)	31.04	26.09
Edmonton Light (CDN$/bbl)	43.61	40.92
Natural gas		
New York Mercantile Exchange (US$/mmbtu)	5.60	3.37
AECO (CDN$/mcf)	6.67	4.03
Foreign exchange rate		
Canadian to U.S. dollar	1.4015	1.5701
U.S. to Canadian dollar	0.7135	0.6369

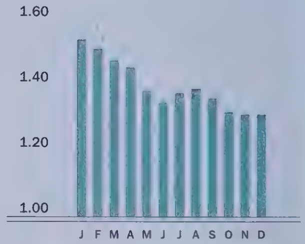
Crude Oil

West Texas Intermediate at Cushing, Oklahoma (WTI) is the benchmark reference for North American crude oil prices. Canadian crude oil prices are based upon postings, primarily at Edmonton, Alberta, and represent the WTI price adjusted for quality and transportation differentials as well as the Canadian/US dollar exchange rate.

In 2003, WTI averaged US$31.04/bbl compared to US$26.09/bbl in 2002 with significant volatility throughout the year ranging from approximately US$25.24/bbl to US$37.83/bbl. At December 31, 2003, WTI closed at US$32.52/bbl and has continued to increase to over US$36.00/bbl in March 2004. The increase in benchmark crude oil prices during 2003 and early into 2004 has been supported by strong supply and demand fundamentals. Several factors affecting these fundamentals include OPEC's determination to hold production quotas in support of higher prices, political risk in the Middle East, the stability of Iraq production, low crude oil and product inventories in North America and increased demand in Asia, particularly China.

During 2003, Canadian crude oil prices were negatively impacted as a result of the strengthening Canadian dollar relative to its U.S. counterpart. The Canadian dollar improved from CDN/US$1.5747 to CDN/US$1.2924 at December 31, 2003.

Heavy oil differentials also widened throughout the year primarily due to an increase in the supply of heavier crudes from new heavy oil projects and reduced demand from refineries.



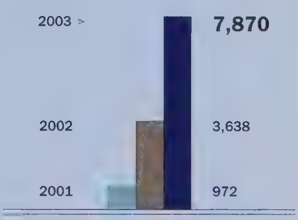
CDN/US Dollar 2003 Monthly Average

Natural Gas

United States natural gas prices are commonly referenced off the New York Mercantile Exchange at the Henry Hub, Louisiana (NYMEX) index price while Canadian natural gas prices are typically referenced to the AECO Hub in Alberta (AECO). Natural gas prices are influenced more by North American supply and demand than global fundamentals. In 2003, the AECO natural gas price averaged $6.67/mcf compared to $4.03/mcf in 2002. Extended cold weather early in 2003 and concerns over low storage inventory levels of natural gas for the 2003/2004 winter heating season resulted in strong prices in the first quarter of 2003 and December while natural gas prices in the summer months remained above $4.75/mcf.

PETROLEUM AND NATURAL GAS SALES

Revenue from petroleum and natural gas sales totaled $7,870,050 in 2003 compared to $3,637,604 in 2002. Substantial increases in both oil and natural gas production volumes combined with significantly higher natural gas prices and slightly higher realized oil prices accounted for the majority of the 116% increase in revenues. Oil revenues for 2003 include a net settlement payment on crude oil and associated U.S. dollar foreign exchange hedging transactions of $476,902 versus $135,575 in 2002. In 2003, oil revenues represented 76% of the Company's total sales versus 94% in 2002 while natural gas accounted for 22% of the year's total sales compared to 5% in 2002. The year-over-year increase in revenue from natural gas sales is consistent with the Company's strategy of balancing its production mix. Royalty revenue increased to $78,403 from $5,561 as a result of an overriding royalty.

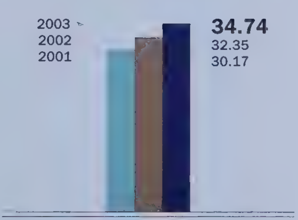


Petroleum & Natural Gas Sales
($000s)

	2003	2002
	$	$
Oil	**5,973,547**	3,411,668
Natural gas	**1,753,010**	188,266
NGLs	**65,090**	32,109
Royalty & other	**78,403**	5,561
	7,870,050	3,637,604

REALIZED PRICES

Oil prices averaged $33.88/bbl compared to $33.21/bbl in 2002 after a net settlement payment on hedging transactions of $2.70/bbl in 2003 compared to $1.32/bbl in 2002. Natural gas prices averaged $6.09/mcf in 2003, a 56% improvement over $3.90/mcf the prior year. Natural gas liquids prices were $29.27/bbl in 2003 compared to $19.24/bbl the prior year. Overall, Virtus received $34.74/boe for 2003 production, a 7% improvement over the $32.35/boe achieved in 2002.



Realized Prices
($/boe)

	2003	2002
	$	$
Oil price before hedges ($/bbl)	**36.58**	34.53
Hedges ($/bbl)	**(2.70)**	(1.32)
Oil price after hedges ($/bbl)	**33.88**	33.21
Natural gas ($/mcf)	**6.09**	3.90
NGLs ($/bbl)	**29.27**	19.24
Average ($/boe)	**34.74**	32.35

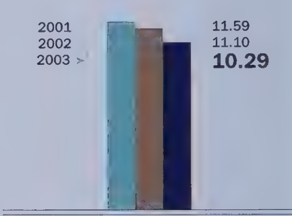
ROYALTIES

Royalties, after the Alberta Royalty Tax Credit, totaled $1,293,191 compared to $612,946 in 2002. The 111% increase in royalties is consistent with the 116% increase in revenues compared to the previous year. Despite higher realized product prices, the average royalty rate decreased from 16.9% to 16.4% of sales due to royalty holidays on several oil wells drilled late in 2002 and early in 2003. These royalty holidays expired early in 2004.

	2003	2002
	$	$
Crown royalties	**1,087,312**	323,609
Freehold royalties	**182,927**	243,999
Overriding royalties	**42,696**	57,886
Alberta Royalty Tax Credit	**(19,744)**	(12,548)
Royalties, net of ARTC	**1,293,191**	612,946
Percentage of sales (%)	**16.4**	16.9

PRODUCTION EXPENSES

Production expenses were up 87% to $2,331,589 from $1,247,878 in 2002 due primarily to the 102% increase in production volumes. Operating expenses per boe fell 7% to $10.29 in 2003 compared to $11.10 a year ago.

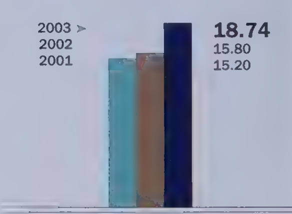


Production Expenses
($/boe)

	2003	2002
	$	$
Production expenses	**2,331,589**	1,247,878
Operating costs ($/boe)	**10.29**	11.10

OPERATING NETBACKS

Operating netbacks for 2003 on a boe basis improved 19% to $18.74 compared to $15.80 the previous year. The increase was a result of higher year-over-year realized prices of $2.39/boe and lower operating costs of $0.81/boe that were offset by higher royalties of $0.26/boe.



Operating Netbacks
($/boe)

	2003	2002
	$/boe	$/boe
Average realized price	**34.74**	32.35
Royalties, net of ARTC	**(5.71)**	(5.45)
Production expenses	**(10.29)**	(11.10)
Operating netback	**18.74**	15.80

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses were up 44% to $1,295,400 versus $896,616 in 2002 due to increases in management, staff, office operations and professional fees associated with year-end reporting requirements. The Company has a policy of not capitalizing general and administrative expenses.

INTEREST

Interest charges totaled $178,444 in 2003 compared to $60,004 in 2002. The 197% increase in interest expense is a result of higher average debt levels maintained throughout the year. Included in interest charges was $1,790 associated with the flow-through share issue in 2002. This compares to interest charges of $28,388 in 2002 associated with the flow-through share issue in 2001.

DEPLETION AND DEPRECIATION

Depletion and depreciation was $2,886,246 for the year compared to $1,066,419 in 2002. The year-over-year increase in depletion and depreciation was due to higher production and an increase in the depletion rate per unit-of-production compared to the prior year. The depletion and depreciation rate, including site restoration and reclamation costs, for 2003 was $12.74/boe compared to $9.48/boe in 2002.

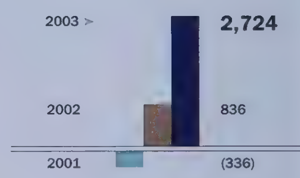
Virtus performs a ceiling test calculation whereby the book value of capital assets is compared to an estimate of future net revenue from the production of proved reserves based upon period-end constant prices and costs. Future net revenue is reduced by general and administrative expenses, financing costs, site restoration costs and income taxes. Any shortfall by which the ceiling test calculation is less than the book value of capitalized assets is charged against earnings in the current year. Using realized prices at year-end resulted in future net revenue being in excess of the book value of capitalized assets for 2003.

FUTURE INCOME TAXES

The Company incurred cash taxes in 2003 of $14,346 for large corporation tax and $65,000 for Saskatchewan resource surcharge. The provision for future income taxes was an expense of $47,319 compared to a recovery of $15,635 in 2002. This reduction resulted in a future income tax liability on the balance sheet of $326,199 since the carrying value of the assets and liabilities on the balance sheet is greater than the tax basis of available deductions. As at December 31, 2003, tax deductions available to the Company to reduce taxable income in future years are estimated to be as follows:

	AMOUNT	RATE OF CLAIM
	$	%
Canadian oil & gas property expense	6,246,071	10
Canadian development expense	733,718	30
Canadian exploration expense	1,368,834	100
Undepreciated production equipment	7,757,902	25
Undepreciated office equipment	190,238	Various
Share issue costs	732,028	20
Net capital loss carry forwards	21,018	100
Attributed Canadian royalty income	186,032	–
	17,235,841	–

Based upon the available tax deductions, anticipated results of operations, capital expenditures and the increase in investment allowance for large corporation tax, Virtus does not anticipate incurring any cash income taxes in 2004.



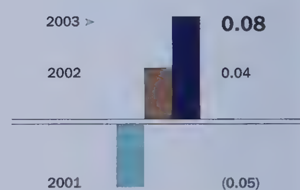
Cash Flow
($000s)

NET LOSS

The Company recorded a net loss for the year ended December 31, 2003 totaling $238,503 compared to the prior year's loss of $214,850. On a per share basis, the loss in both years was $(0.01) per share.

CASH FLOW FROM OPERATIONS

Cash flow from operations totaled $2,724,093 or $0.08 per share in 2003 compared to $835,934 or $0.04 per share recorded in the previous year. The increase in cash flow from operations was primarily due to higher realized natural gas prices and significantly increased oil and natural gas production volumes.

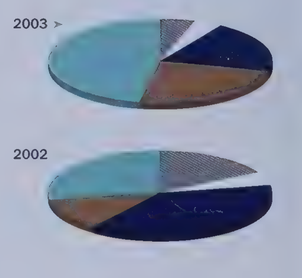


Cash Flow Per Share
($)

CAPITAL EXPENDITURES

In 2003, capital expenditures totaled $12,560,697, of which 47% was for the acquisition of producing oil and natural gas properties, 24% for production equipment to tie-in new production and expand fluid handling capacity, and 20% for drilling and completions operations. The Company's capital expenditures for the past two years are summarized as follows:

	2003	2002
	$	$
Land	**611,475**	1,134,169
Geological & geophysical	**487,875**	316,956
Drilling & completions	**2,478,915**	2,461,678
Production equipment	**3,005,215**	760,071
Acquisition of properties & equipment	**5,903,148**	1,827,800
Office furniture & equipment	**74,069**	44,880
	12,560,697	6,545,554



Capital Expenditures
(%)

	2003	2002
Land	**5**	17
Geological & Geophysical	**4**	5
Drilling & Completions	**20**	38
Production Equipment	**24**	12
Acquisitions	**47**	28

During the year, the Company disposed of producing and non-producing oil and natural gas reserves for total proceeds of $1,972,030. In January 2004, the Company acquired producing oil properties for $550,000 and in February 2004, disposed of producing oil properties for proceeds of $600,000.

NET ASSET VALUE

At December 31, 2003, the net asset value of the Company on a fully diluted basis using the present value of before tax forecast prices and costs reserves, various discount rates and assuming the exercise of all stock options is as follows:

	DISCOUNT RATE	
	10%	15%
	$	$
Proved reserves	**12,409,000**	**11,467,000**
Probable reserves	**2,628,000**	**2,205,000**
Proved plus probable reserves	**15,037,000**	**13,672,000**
Undeveloped land & seismic	**3,271,000**	**3,271,000**
Bank debt & working capital deficit	**(4,309,369)**	**(4,309,369)**
Proceeds from all options	**1,362,500**	**1,362,500**
Net asset value	**15,361,131**	**13,996,131**
Fully diluted common shares	**38,846,181**	**38,846,181**
Net asset value per share	**0.40**	**0.36**

Liquidity and Capital Resources

FUNDING

The Company's sources of cash totaled $10,536,959 versus cash uses of $12,611,959 compared to $8,837,847 and $7,387,847, respectively, in 2002. Consequently, bank debt increased $2,075,000 in 2003 compared to a reduction of $1,450,000 recorded a year ago.

	2003	2002
	$	$
Sources		
Cash flow from operations	**2,724,093**	835,934
Issue of common shares, net	**3,296,608**	7,424,406
Working capital	**2,406,728**	–
Collection of other receivables	**137,500**	223,785
Proceeds from disposition of capital assets	**1,972,030**	353,722
	10,536,959	8,837,847
Uses		
Additions to capital assets	**12,560,697**	6,545,554
Site restoration & reclamation	**51,262**	1,288
Working capital	**–**	841,005
	12,611,959	7,387,847
Increase (decrease) in bank debt	**2,075,000**	(1,450,000)

SHARE CAPITAL

On July 24, 2003, the Company closed a private placement of 3,900,000 flow-through common shares at $0.78 per share for gross proceeds of $3,042,000.

During the year, the Company issued 1,169,663 common shares as a result of the exercise of common share purchase warrants at $0.40 per share for total proceeds of $467,865 and issued 112,500 common shares on the exercise of stock options for total proceeds of $50,625.

At the Annual General and Special Meeting of Shareholders held on June 12, 2002, the Company's shareholders approved a reduction of stated share capital of common shares by an amount equal to the deficit on the balance sheet at December 31, 2001 of $3,423,242.

COMMON SHARES OUTSTANDING

At December 31, 2003, 36,162,431 common shares were outstanding compared to 30,980,268 common shares the prior year. During the first quarter of 2004, the Company issued 323,333 common shares on the exercise of stock options by a former officer resulting in 36,485,764 common shares outstanding as at March 31, 2004. At December 31, 2003, 2,683,750 stock options at a weighted average exercise price of $0.51 per share were outstanding. As at March 31, 2004, the Company had 2,975,750 stock options outstanding.

BANK DEBT

The Company currently has a credit facility with the National Bank of Canada totaling $5,875,000 bearing interest at the rate of prime plus 0.625% per annum. This facility is secured by a $7,500,000 debenture and a floating charge over all assets. The Company also has an acquisition/development facility of $2,000,000 bearing interest at prime plus 1.0% per annum. At March 31, 2004, Virtus had outstanding bank debt of $2,700,000 and a working capital deficit of approximately $3,000,000.

The Company recognizes the importance of maintaining a strong balance sheet and strives to maintain a bank debt to forward cash flow ratio of 1.5 to 1.0, or lower.

Accounting Policies

The financial statements of the Company have been prepared by management in accordance with generally accepted accounting principles in Canada as disclosed in the notes to the financial statements. The preparation of financial statements in conformity with generally accepted accounting principles requires management to adopt accounting policies, which may involve choosing between alternative accounting methods, to properly reflect the nature of the Company's activities. The significant accounting polices, for which there exist alternative accounting methods, adopted by the Company are summarized below:

PETROLEUM AND NATURAL GAS OPERATIONS

The full cost method of accounting for petroleum and natural gas operations capitalizes all costs associated with the exploration for and development of petroleum and natural gas reserves. The costs of all successful and unsuccessful petroleum and natural gas operations are initially capitalized on the balance sheet and charged to earnings on a unit-of-production method based upon total proved reserves. Successful efforts accounting for petroleum and natural gas operations provides for the capitalization of those costs associated with successful operations followed by a charge to earnings of those costs on a unit-of-production basis. The costs of unsuccessful operations are immediately charged to earnings. The Company has adopted the full cost method of accounting for petroleum and natural gas operations as it more appropriately reflects the nature of the risk in exploring for and the development of petroleum and natural gas.

FLOW-THROUGH SHARES

The resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. The provision for future income taxes is increased by the renounced tax deductions at the time the flow-through shares are issued or as the qualifying flow-through expenditures are incurred. The Company has adopted the policy of recognizing the future income tax liability associated with the renounced tax deductions as the expenditures are incurred. Effective January 1, 2004, the Company will be required to recognize the future income tax liability as renounced.

Accounting Estimates

The application of Canadian generally accepted accounting principles involves certain assumptions, estimates and judgements that affect reported amounts of assets, liabilities, revenues and expenses. These estimates are based upon historical experience and various other assumptions that management believes to be reasonable. Actual results could differ from these estimates under different assumptions or conditions, and as a consequence, the application of these principles can produce varying results from company to company. By their nature, these estimates are subject to measurement uncertainty and could have the most significant impact on the financial statements in the following areas:

OIL AND NATURAL GAS RESERVES

The oil and gas reserve estimates are made using all available geological, reservoir and historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the Company's plans.

FULL COST ACCOUNTING

Depletion and Depreciation

The Company uses the full cost method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development are capitalized whether successful or not. The aggregate of net capitalized costs and estimated future development costs less estimated salvage values is amortized using the unit-of-production method based upon estimated proved oil and gas reserves. An increase in estimated proved oil and gas reserves would result in a corresponding reduction in depletion expense. A decrease in estimated future development costs would result in a corresponding reduction in depletion expense.

Withheld Costs

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted or, if the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to earnings.

IMPAIRMENT OF PROPERTY AND EQUIPMENT

The Company is required to review the carrying value of all property and equipment, including the carrying value of oil and gas assets, for potential impairment. Impairment is indicated if the carrying value of the long-lived asset or oil and gas cost centre is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings.

SITE RESTORATION AND RECLAMATION

The Company is required to provide for future removal and site restoration costs. The Company must estimate these costs in accordance with existing laws, contracts or other policies. These estimated costs are charged to earnings and the appropriate liability account over the expected service life of the asset. When the future removal and site restoration costs cannot be reasonably determined, a contingent liability may exist. Contingent liabilities are charged to earnings when management is able to determine the amount and the likelihood of the future obligation.

TAXES

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Financial Reporting Update

There have been several changes in the financial reporting and securities regulatory environment in 2003 that have impacted all public companies. The new and amended standards are expected to impact the Company in 2004 as follows:

ASSET RETIREMENT OBLIGATIONS

The CICA issued Section 3110 in 2004 that requires companies to recognize the liability associated with future site reclamation costs in the financial statements at the time when the liability is incurred. The new Canadian standard is effective for fiscal years beginning on or after January 1, 2004, but earlier adoption is encouraged. The Company will be complying with this standard in 2004. As a result of implementation, the liability on the balance sheet for site restoration and reclamation is expected to increase to $1,595,475 and the property and equipment balance to increase by $1,221,199. The net loss after applicable income taxes for 2003 decreased $36,759 compared to the net loss that was reported under the old standard. The transitional provisions of this section require that the standard be applied retroactively with restatement of comparative periods. As a result of the retroactive application, 2003 comparative numbers will be restated to reflect the impact of this standard on the 2004 financial statements. The deficit as at January 1, 2004 decreased $7,159 net of applicable income taxes for the cumulative impact of retroactive restatement of all prior quarters and years.

STOCK-BASED COMPENSATION AND OTHER STOCK-BASED PAYMENTS

In September 2003, the CICA issued an amendment to section 3970 "Stock-Based Compensation and Other Stock-Based Payments." The amended section is effective for fiscal years beginning on or after January 1, 2004, but earlier adoption is encouraged. The Company will be complying with this standard in 2004. The amendment requires that companies measure all stock-based payments using the fair value method of accounting and recognize the compensation expense in their financial statements. As a result of implementation, as at January 1, 2004 the contributed surplus and deficit on the balance sheet are expected to increase $285,836 for the cumulative impact of retroactive restatement of prior years. Quarterly reporting in 2004 will include the restatement of 2003 comparative figures to include the retroactive adjustment of prior years.

FULL COST ACCOUNTING GUIDELINE

In September 2003, the CICA issued Accounting Guideline 16 "Oil and Gas Accounting – Full Cost" to replace CICA Accounting Guideline 5. The new guideline proposes amendments to the ceiling test calculation applied by the Company. The new guideline is effective for fiscal years beginning on or after January 1, 2004. Implementation of this new guideline is not expected to impact the Company's financial results for 2004 or the prior year.

HEDGING RELATIONSHIPS

In December 2001, the CICA issued Accounting Guideline 13 "Hedging Relationships" that deals with the identification, designation, documentation and measurement of effectiveness of hedging relationships for the purposes of applying hedge accounting. The guideline is effective for fiscal years beginning on or after July 1, 2003.

CONTINUOUS DISCLOSURE OBLIGATIONS

Effective March 31, 2004, all reporting issuers in Canada will be subject to new disclosure requirements as per National Instrument 51-102 "Continuous Disclosure Obligations." This new instrument is effective for fiscal years beginning on or after January 1, 2004. The instrument proposes shorter reporting periods for filing of annual and interim financial statements, management's discussions and analysis, and annual information forms. The Company continues to assess the implications of this new instrument that will be implemented in 2004.

Contractual Obligations

The Company has contracted firm receipt transportation of 780 mcf/d on the TransCanada gas transmission system for a one-year term ending January 31, 2005.

Commitments

At December 31, 2003, the Company had an obligation to incur qualifying expenditures of $1,845,247 to satisfy the terms of the flow-through common shares issued during the year. The Company is committed to an operating lease for its office premises until January 31, 2006 with payments as follows: 2004 – $283,112; 2005 – $296,437; and 2006 – $24,796.

Business Risks

Crude oil and natural gas exploration, development and production involve a number of business risks, some of which are beyond the Company's control. These can be categorized as operational, financial and regulatory risks.

Operational risks include finding and developing reserves economically, marketing production, hiring and retaining skilled employees and contractors, and conducting operations in a cost effective and safe manner. The Company continuously monitors and responds to changes in these factors and regulations governing its operations. Insurance is also maintained at levels consistent with prudent industry practices to minimize risks.

The philosophy of the Company's risk management program is to use hedging as a tool to increase the certainty of cash flow in order to pursue its capital spending program. Hedging contracts consist of forward sales agreements or costless collars so there is no upfront cost to the Company. The Company's policy is to not utilize derivative financial instruments for trading or speculative purposes. All transactions related to the Company's financial risk management program are approved by the Board of Directors in advance of signing any contracts.

Financial risks include commodity prices, interest rates and the Canadian/US currency exchange rate, all of which are beyond the Company's control. Virtus has a risk management program whereby the commodity price associated with a portion of its future production is fixed. The Company sold forward a portion of its future production through a combination of fixed price sales contracts with customers and swap agreements with financial counterparties.

During the year, the Company incurred a loss of $599,372 (2002 - $135,575) on fixed price crude oil contracts and a gain of $122,470 (2002 – $nil) on a Canadian to U.S. dollar foreign exchange rate contract.

As at December 31, 2003, the Company had the following fixed price contracts applicable to future production outstanding:

TIME PERIOD	COMMODITY	TYPE OF CONTRACT	QUANTITY HEDGED	HEDGED PRICE
Jan. 1, 2004 - Mar. 31, 2004	Crude oil	Physical	150 bbls/d	US$27.30/bbl
Apr. 1, 2004 - Jun. 30, 2004	Crude oil	Physical	150 bbls/d	US$26.40/bbl

SEDAR

A more comprehensive discussion of the Company's business strategies and objectives can be found in the Company's 2002 Annual Report and other public information, which can be accessed on the Company's website at www.virtusenergy.com and on SEDAR at www.sedar.com.

Management's report

The accompanying financial statements of Virtus Energy Ltd. and all information in this Annual Report are the responsibility of management and have been approved by the Board of Directors.

The financial statements have been prepared by management in accordance with accounting principles generally accepted in Canada and within the framework of the Company's significant accounting policies as described in the notes to the financial statements. The financial statements reflect management's best estimates and judgements based on currently available information within reasonable limits of materiality.

Financial information presented throughout the Annual Report has been prepared and reviewed by management to ensure it is consistent with that shown in the financial statements.

Management is responsible for the integrity of the financial statements. Management maintains appropriate systems of internal control to provide reasonable assurance that transactions are appropriately authorized, assets are safeguarded and financial records are properly maintained to provide reliable financial information for the preparation of financial statements.

Independent auditors are appointed by the shareholders of the Company to perform an examination of the corporate and accounting records so as to express an opinion on the financial statements. Their examination included a review and evaluation of the system of internal controls and included such tests and other procedures, as they considered necessary, to provide reasonable assurance that the financial statements are presented fairly.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the financial statements. The Board carries out this responsibility through its Audit Committee. The Audit Committee meets with management and the independent auditors to satisfy itself that management's responsibilities are properly discharged, to review the financial statements and recommend the financial statements be presented to the Board of Directors for approval.

The financial statements, including the notes to the financial statements, have been approved by the Board of Directors on the recommendation of the Audit Committee.

PETER A. CARWARDINE
President & Chief Executive Officer
March 25, 2004 - Calgary, Canada

BRIAN P. KOHLHAMMER
Vice President, Finance & Chief Financial Officer

Auditors' report

We have audited the balance sheets of Virtus Energy Ltd. as at December 31, 2003 and 2002 and the statements of operations and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

CHARTERED ACCOUNTANTS

March 25, 2004 - Calgary, Canada

Balance sheets

AS AT DECEMBER 31,	2003	2002
	$	$
ASSETS		
Current assets		
Cash	–	1,420,394
Accounts receivable	1,600,985	877,995
Other receivables	–	137,500
Prepaid expenses	63,456	48,918
	1,664,441	2,484,807
Future income taxes (NOTE 5)	–	299,769
Property and equipment (NOTE 2)	18,162,086	10,137,666
	19,826,527	12,922,242
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Outstanding cheques	193,097	–
Accounts payable and accrued liabilities	3,705,713	2,174,948
Bank debt (NOTE 3)	2,075,000	–
	5,973,810	2,174,948
Site restoration and reclamation	385,226	114,489
Future income taxes (NOTE 5)	326,199	–
Shareholders' equity (NOTE 4)		
Share capital	13,565,614	10,847,655
Contributed surplus	29,031	–
Deficit	(453,353)	(214,850)
	13,141,292	10,632,805
Commitment (NOTES 4(B) AND 8)		
Subsequent events (NOTE 9)		
	19,826,527	12,922,242

See accompanying notes to financial statements.

On behalf of the Board of Directors,

OWEN C. PINNELL

Director

KEITH E. MACDONALD

Director

Statements of operations and deficit

YEARS ENDED DECEMBER 31,	2003	2002
	$	$
REVENUES		
Petroleum and natural gas sales	**7,870,050**	3,637,604
Royalties, net of ARTC	**(1,293,191)**	(612,946)
Other income	**2,982**	15,774
	6,579,841	3,040,432
EXPENSES		
Production	**2,331,589**	1,247,878
General and administrative	**1,295,400**	896,616
Interest	**178,444**	60,004
Depletion and depreciation	**2,886,246**	1,066,419
	6,691,679	3,270,917
Loss before taxes	**(111,838)**	(230,485)
Taxes (reduction) (NOTE 5)	**126,665**	(15,635)
Net loss	**(238,503)**	(214,850)
Deficit, beginning of year	**(214,850)**	(3,423,242)
Elimination of deficit (NOTE 4(B))	**–**	3,423,242
Deficit, end of year	**(453,353)**	(214,850)
Loss per share (NOTE 4(F))		
Basic and diluted	**(0.01)**	(0.01)

See accompanying notes to financial statements.

Statements of cash flows

YEARS ENDED DECEMBER 31,	2003	2002
	$	$
Cash provided by (used in):		
OPERATIONS		
Net loss	(238,503)	(214,850)
Items not involving cash:		
Depletion and depreciation	2,886,246	1,066,419
Stock-based compensation	29,031	–
Future income tax expense (reduction)	47,319	(15,635)
Funds from operations	2,724,093	835,934
Change in non-cash operating working capital (NOTE 6)	529,334	560,455
	3,253,427	1,396,389
FINANCING		
Issue of common shares, net	3,296,608	7,424,406
Borrowing (repayment) of bank debt	2,075,000	(1,450,000)
Other receivables	137,500	223,785
	5,509,108	6,198,191
INVESTMENTS		
Acquisition of property and equipment	(12,560,697)	(6,545,554)
Proceeds from disposition of property and equipment	1,972,030	353,722
Site restoration and reclamation	(51,262)	(1,288)
Change in non-cash investing working capital	457,000	–
	(10,182,929)	(6,193,120)
Increase (decrease) in cash	(1,420,394)	1,401,460
Cash, beginning of year	1,420,394	18,934
Cash, end of year	–	1,420,394
Supplemental cash flow information:		
Interest paid	177,879	49,841
Taxes paid	1,763	–

See accompanying notes to financial statements.

Notes to financial statements

December 31, 2003 and 2002

Nature of Operations

Virtus Energy Ltd. (the "Company") is a resource-based company engaged in the exploration for, and the development and production of crude oil, natural gas and natural gas liquids in Western Canada.

1. SIGNIFICANT ACCOUNTING POLICIES

The financial statements of the Company have been prepared by management in accordance with generally accepted accounting principles in Canada. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates. The financial statements have, in management's opinion, been properly prepared using careful judgement with reasonable limits of materiality and within the framework of the significant accounting policies summarized below:

(a) Petroleum and Natural Gas Operations

The Company follows the full cost method of accounting whereby all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized. Such costs include land acquisition costs, geological and geophysical costs, lease rental costs on non-producing properties, costs of both productive and unproductive drilling and production equipment. Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the depletion rate of 20% or more.

The accumulated costs, less the costs of acquisition of unproved properties, are depleted and depreciated using the unit-of-production method based upon total proved reserves before royalties as determined by independent evaluators. Natural gas reserves and production are converted into equivalent barrels of oil based upon the estimated relative energy content.

The costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations. These properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of impairment is added to the costs subject to depletion.

The net carrying amount of the Company's petroleum and natural gas properties is limited to a ceiling, being the aggregate of future net revenues from proved reserves, less future capital costs plus the costs of unproved properties, net of impairment allowances, less future site restoration costs, general and administrative costs, financing costs and income taxes. Future net revenues have been calculated using prices and costs in effect at the Company's year-end without escalation or discounting.

Depreciation of furniture and office equipment is provided using the declining balance method based upon estimated useful lives of 20% to 50%.

(b) Future Site Restoration and Abandonment Costs

Site restoration and abandonment costs are provided for over the life of the estimated proved reserves on a unit-of-production basis. Costs are estimated each year by management in consultation with the Company's engineers based upon current regulations, costs, technology and industry standards. The period charge is included in depletion and depreciation and actual site restoration and abandonment expenditures are charged to the accumulated provision account as incurred.

(c) Interest in Joint Ventures

A portion of the Company's oil and gas exploration and development activities are conducted jointly with others, and accordingly, the financial statements reflect only the Company's proportionate interest in such activities.

1. SIGNIFICANT ACCOUNTING POLICIES (continued)

(d) Future Income Taxes

The Company follows the tax liability method of accounting for income taxes. Under this method, future tax assets and liabilities are determined based upon differences between the carrying value and the tax basis of assets and liabilities, and measured using the substantively enacted tax rates and laws expected to be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in earnings in the period in which the change occurs. A valuation allowance is recorded against any future income tax assets if it is more likely than not that the asset will not be realized.

(e) Stock-Based Compensation

Proceeds received on exercise of options are recorded to share capital and no compensation expense is recognized when employee stock options are granted. For stock-based compensation to non-employees, the Company will calculate a fair value using an option pricing model, and charge the value to operations over the vesting period of the options.

(f) Flow-Through Shares

The resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. The provision for future income taxes is increased and share capital is reduced by the renounced tax deductions when the expenditures are incurred.

(g) Per Share Information

Basic loss per share is computed by dividing net loss by the weighted average number of common shares outstanding for the year. Diluted per share amounts reflect the potential dilution that could occur if securities or other contracts to issue common shares were exercised or converted to common shares. The treasury-stock method is used to determine the dilutive effect of stock options and other dilutive instruments. Anti-dilutive options are not included in the calculation.

(h) Measurement Uncertainty

The amounts recorded for depletion and depreciation and impairment of petroleum and natural gas properties and equipment and the provision for site restoration and reclamation costs are based upon estimates of proved petroleum and natural gas reserves, production rates, commodity prices and future costs. The ceiling test is based upon estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements of changes to estimates in future periods could be material.

(i) Financial Instruments

The Company may enter into derivative instrument contracts to manage its exposure related to petroleum and natural gas prices and foreign currency fluctuations. The Company's policy is to not utilize derivative financial instruments for trading or speculative purposes. Settlement amounts on commodity and foreign currency hedge contracts are recognized in earnings as the related production revenues are recorded.

A derivative instrument must be designated and effective to be accounted for as a hedge. For cash flow hedges, effectiveness is achieved if the changes in the cash flows of the derivative instrument substantially offset the changes in the cash flows of the hedged position and the timing of the cash flows is similar. Effectiveness for fair value hedges is achieved if the fair value of the derivative instrument substantially offsets changes in the fair value attributable to the hedged item. In the event that a derivative instrument does not meet the designation or effectiveness criterion, the gain or loss on the derivative instrument is recognized in earnings. If a derivative instrument that qualifies as a hedge is settled early, the gain or loss at settlement is deferred and recognized when the gain or loss on the hedged transaction is recognized. Premiums paid or received with respect to derivative instruments that are hedges are deferred and amortized to earnings over the term of the hedge.

2. PROPERTY AND EQUIPMENT

	COST	ACCUMULATED DEPLETION AND DEPRECIATION	NET BOOK VALUE
	$	$	$
2003			
Petroleum and natural gas properties	**17,429,721**	**6,003,883**	**11,425,838**
Production equipment	**8,776,057**	**2,157,067**	**6,618,990**
Furniture and office equipment	**215,093**	**97,835**	**117,258**
	26,420,871	**8,258,785**	**18,162,086**
2002			
Petroleum and natural gas properties	12,180,137	4,262,883	7,917,254
Production equipment	3,511,043	1,357,067	2,153,976
Furniture and office equipment	141,024	74,588	66,436
	15,832,204	5,694,538	10,137,666

As at December 31, 2003, the estimated site restoration and reclamation costs to be accrued over the life of the remaining proved reserves were $2,155,000 (2002 - $635,000). During the year, the Company recorded a provision for site restoration and reclamation of $321,999 (2002 - $59,000).

As at December 31, 2003, costs in the amount of $1,258,000 (2002 - $1,226,000) representing unproved properties were excluded from depletion calculations and future development costs of $1,149,000 (2002 - $1,057,000) have been included in costs subject to depletion.

The Company does not capitalize any direct or indirect general and administrative costs.

3. BANK DEBT

	2003	2002
	$	$
Bank debt	**2,075,000**	–

At December 31, 2003, the Company had a revolving operating loan facility, with a Canadian chartered bank, of $5,800,000 less letters of credit totaling $62,745. Advances bear interest at the bank prime rate plus 0.625% and are secured by a $7,500,000 debenture with a floating charge over all assets of the Company.

4. SHARE CAPITAL

(a) **Authorized**

Unlimited number of common voting shares
Unlimited number of first preferred shares, of which none have been issued
Unlimited number of second preferred shares, of which none have been issued

4. SHARE CAPITAL (continued)

(b) Issued and Outstanding

	SHARES	AMOUNT
	#	$
December 31, 2001	13,485,268	7,507,357
Private placement of common shares	195,000	78,000
Private placement of common shares	7,500,000	3,000,000
Private placement of common shares	7,300,000	3,504,000
Private placement of flow-through common shares	2,500,000	1,500,000
Tax effect of flow-through common shares	–	(942,316)
Share issue costs (net of $281,450 income tax effect)	–	(376,144)
Reduction in share capital	–	(3,423,242)
December 31, 2002	30,980,268	10,847,655
Exercise of share purchase warrants	**1,169,663**	**467,865**
Exercise of options	**112,500**	**50,625**
Private placement of flow-through common shares	**3,900,000**	**3,042,000**
Tax effect of flow-through common shares	**–**	**(679,346)**
Share issue costs (net of $100,697 income tax effect)	**–**	**(163,185)**
December 31, 2003	**36,162,431**	**13,565,614**

As at December 31, 2003, the Company had an obligation to incur qualifying exploration expenditures of $1,845,247 to satisfy the terms of the flow-through common shares issued during the year.

At the Annual General and Special Shareholders meeting held on June 12, 2002, the shareholders of the Company approved the reduction of stated share capital of the common shares of the Company by an amount equal to the deficit on the balance sheet at December 31, 2001 of $3,423,242. This results in a reduction of the deficit by an equal amount but has no effect on the net book value of shareholders' equity.

(c) Stock Options

The Company grants stock options to management, employees, directors and key consultants at the market price of the common shares at the time of grant. The options have a vesting period ranging from immediate to three years, as approved by the Board, with a term not to exceed five years from the date of grant. At December 31, 2003, there were 2,683,750 common shares of the Company reserved for issuance under the stock option plan.

The following table summarizes the changes in the number of options and the weighted average prices:

	2003		2002	
	OPTIONS	WEIGHTED AVERAGE EXERCISE PRICE	OPTIONS	WEIGHTED AVERAGE EXERCISE PRICE
	#	$	#	$
Stock options outstanding, beginning of year	**2,478,750**	**0.50**	718,750	0.40
Granted	**555,000**	**0.52**	1,835,000	0.54
Exercised	**(112,500)**	**0.45**	–	–
Cancelled	**(237,500)**	**0.50**	(75,000)	0.40
Stock options outstanding, end of year	**2,683,750**	**0.51**	2,478,750	0.50
Exercisable at year-end	**1,472,498**	**0.49**	1,125,625	0.46

4. SHARE CAPITAL (continued)

(c) Stock Options (continued)

The following table summarizes information about the stock options outstanding and exercisable at December 31, 2003:

	OPTIONS OUTSTANDING		OPTIONS EXERCISABLE	
RANGE OF EXERCISE PRICE	OPTIONS OUTSTANDING	WEIGHTED AVERAGE REMAINING TERM	EXERCISABLE	WEIGHTED AVERAGE EXERCISE PRICE
$	#	Years	#	$
0.40 - 0.49	**1,068,750**	**3.2**	**768,750**	**0.41**
0.50 - 0.59	**597,500**	**3.9**	**199,165**	**0.50**
0.60 - 0.69	**992,500**	**3.4**	**504,583**	**0.61**
0.70 - 0.79	**25,000**	**4.9**	**–**	**0.77**
	2,683,750	**3.5**	**1,472,498**	**0.49**

(d) Stock-Based Compensation

During 2003, compensation expense recorded for stock options granted to key consultants totaled $29,031 (2002 - $nil). No compensation expense has been recognized for stock options granted to employees and directors. Had compensation expense been determined based upon the fair value method for awards made after December 31, 2001 to employees and directors, the Company's net loss and loss per share would have been adjusted to the pro forma amounts indicated below:

	2003	2002
	$	$
Net loss for the year - as reported	**(238,503)**	(214,850)
Net loss for the year - pro forma	**(373,939)**	(365,250)
Loss per share (basic and diluted) - as reported	**(0.01)**	(0.01)
Loss per share (basic and diluted) - pro forma	**(0.01)**	(0.02)

The pro forma amounts exclude the effect of stock options granted prior to January 1, 2002. The weighted average fair value of options granted during the year ended December 31, 2003 was $0.38 (2002 - $0.17) per option using the Black-Scholes option pricing model. The following table sets out the assumptions used in applying the Black-Scholes model:

	2003	2002
Risk free interest rate (%)	**5.0**	5.0
Expected life (years)	**4**	4
Expected volatility (%)	**106**	30

4. SHARE CAPITAL (continued)

(e) Share Purchase Warrants

The following table summarizes information about share purchase warrants:

	WARRANT	EXERCISE PRICE	EXPIRY DATE
	#	$	
December 31, 2001	597,788	0.40	May-Jun. 2003
Warrants issued	10,875	0.40	Jul. 15, 2003
Warrants issued	562,500	0.40	Sep. 19, 2003
December 31, 2002	1,171,163	0.40	–
Warrants exercised	**(1,169,663)**	**0.40**	–
Warrants expired	**(1,500)**	**0.40**	–
December 31, 2003	–	–	–

(f) Weighted Average Number of Shares

The weighted average number of common shares issued and outstanding for the year ended December 31, 2003 was 33,258,717 (2002 - 21,435,830). In calculating the loss per share, options and warrants totaling 2,683,750 (2002 - 3,649,913) were excluded from the dilution calculation, as they were antidilutive.

5. TAXES

Taxes are comprised of the following:

	2003	2002
	$	$
Large corporation tax and Saskatchewan resource surcharge	**79,346**	–
Future income tax expense (reduction)	**47,319**	(15,635)
	126,665	(15,635)

The actual income tax provision differs from the expected amount calculated by applying the Canadian combined federal and provincial corporate income tax rate to loss before taxes. The major components of these differences are explained as follows:

	2003	2002
	$	$
Loss before income taxes	**(111,838)**	(230,485)
Corporate income tax rate (%)	**41.14**	42.80
Expected future income tax recovery	**(46,010)**	(98,648)
Increase (decrease) in future income taxes resulting from:		
Non-deductible crown charges	**406,651**	147,517
Alberta Royalty Tax Credit	**(7,528)**	(5,370)
Resource allowance	**(262,906)**	(97,856)
Other	**(5,118)**	24,088
Non-deductible expenses	**4,362**	4,253
Change in corporate tax rates	**(42,132)**	(23,619)
Large corporation tax and Saskatchewan resource surcharge	**79,346**	–
Amendments to prior years' tax returns	–	34,000
	126,665	(15,635)

5. TAXES (continued)

The components of the net future income tax asset (liability) are as follows:

	2003	2002
	$	$
Future income tax assets (liabilities):		
Property and equipment	**(762,140)**	(338,631)
Share issue costs	**279,342**	309,128
Site restoration and reclamation	**133,345**	36,751
Non-capital loss carry forwards	**–**	282,585
Attributed Canadian royalty income	**23,254**	9,936
Net future income tax asset (liability)	**(326,199)**	299,769

6. CHANGE IN NON-CASH OPERATING WORKING CAPITAL

	2003	2002
	$	$
Accounts receivable	**(722,990)**	(541,600)
Prepaid expenses	**(14,538)**	(403)
Outstanding cheques	**193,097**	–
Accounts payable and accrued liabilities	**1,073,765**	1,102,458
	529,334	560,455

7. FINANCIAL INSTRUMENTS

The Company's financial instruments included in the balance sheet are comprised of accounts receivable, other receivables, accounts payable and accrued liabilities and bank debt.

Credit Risk
The Company's accounts receivable are due from a diverse group of customers and as such are subject to normal credit risks.

Interest Rate Risk
The Company is also exposed to interest rate risk to the extent that bank debt is at a floating rate of interest.

Fair Values
The fair values of the Company's financial instruments other than bank debt approximate their respective carrying values due to their short-term nature. The Company's bank debt bears interest at a floating market rate, and accordingly, the fair market value approximates the carrying value.

The Company has a risk management program whereby the commodity price associated with a portion of its future production is fixed. The Company sells forward a portion of its future production through a combination of fixed price sales contracts with customers and swap agreements with financial counterparties. The contracts are subject to market risk from fluctuating commodity prices and exchange rates, however, gains or losses on the contracts are offset by changes in the value of the Company's production.

7. FINANCIAL INSTRUMENTS (continued)

As at December 31, 2003, the Company had fixed the price applicable to future production through the following forward contracts:

TIME PERIOD	COMMODITY	TYPE OF CONTRACT	QUANTITY HEDGED	HEDGED PRICE
Jan. 1, 2004 - Mar. 31, 2004	Crude oil	Physical	150 bbls/d	US$27.30/bbl
Apr. 1, 2004 - Jun. 30, 2004	Crude oil	Physical	150 bbls/d	US$26.40/bbl

The Company made net settlement payments on hedging transactions during 2003 in the amount of $476,902 (2002 - $135,575).

8. COMMITMENT

The Company is committed, under an operating lease for its office premises, to the following minimum lease payments to the expiration of the lease on January 31, 2006.

	$
2004	283,112
2005	296,437
2006	24,796

The Company has sublet approximately one-half of its office premises, at the Company's lease rate per square foot, from January 1, 2004 to July 31, 2004, which is not reflected in the above amounts.

9. SUBSEQUENT EVENTS

In January 2004, the Company acquired producing oil properties for $550,000 and in February 2004, disposed of producing oil properties for proceeds of $600,000.

Historical review

	2001	2002	Q1	Q2	Q3	Q4	2003
OPERATING RESULTS							
Production							
Oil (bbls/d)	31	281	362	540	477	552	**483**
Natural gas (mcf/d)	280	132	147	614	1,057	1,322	**789**
NGLs (bbls/d)	10	5	5	5	4	11	**6**
Total (boe/d)	88	308	391	647	657	783	**621**
Realized prices							
Oil ($/bbl)	27.41	33.21	35.18	35.57	33.61	31.64	**33.88**
Natural gas ($/mcf)	5.48	3.90	7.12	6.40	5.96	5.93	**6.09**
NGLs ($/bbl)	22.19	19.24	31.50	25.38	27.79	30.52	**29.27**
Average ($/boe)	30.17	32.35	35.63	36.04	34.22	33.68	**34.74**
Operating netback							
Average ($/boe)	15.20	15.80	17.77	20.65	18.49	17.87	**18.74**
Reserves							
Oil & NGLs							
Proved (mbbls)	458	769					**938**
Probable (mbbls)	32	202					**195**
Natural gas							
Proved (mmcf)	916	1,780					**1,447**
Probable (mmcf)	846	1,433					**558**
Land							
Undeveloped (net acres)	12,678	44,120					**29,295**
(000s, except per share amounts)	$	$	$	$	$	$	$
FINANCIAL RESULTS							
Petroleum & natural gas sales	972	3,638	1,255	2,121	2,068	2,426	**7,870**
Cash flow from operations	(336)	836	316	797	856	755	**2,724**
Per share - basic	(0.05)	0.04	0.01	0.03	0.02	0.02	**0.08**
Net earnings (loss)	(1,731)	(215)	(48)	51	(11)	(230)	**(238)**
Per share - basic	(0.28)	(0.01)	–	–	–	(0.01)	**(0.01)**
Capital expenditures	4,512	6,546	1,125	6,625	1,967	2,844	**12,561**
Total assets	6,663	12,922	12,915	17,108	18,253	19,827	**19,827**
Bank debt	1,450	–	–	4,215	1,050	2,075	**2,075**
Working capital (surplus) deficit	417	(310)	502	176	1,198	2,234	**2,234**
Shareholders' equity	4,084	10,633	10,376	10,677	13,753	13,141	**13,141**
(000,000s)	#	#	#	#	#	#	#
COMMON SHARE DATA							
Common shares outstanding							
Total	13.5	31.0	31.0	31.7	36.2	36.2	**36.2**
Weighted average	6.3	21.4	31.0	31.2	34.6	36.2	**33.3**

Corporate information

BOARD OF DIRECTORS

Peter A. Carwardine (3)
President & Chief Executive Officer
Virtus Energy Ltd.

Ian M. Fergusson (2)(3)
Vice President
Camcor Capital Inc.

Keith E. Macdonald (1)(2)
Independent Businessman

Owen C. Pinnell (1)(3)
Chairman
Virtus Energy Ltd.

J. Ronald Woods (1)(2)
Independent Businessman

(1) Audit & Reserves Committee Member
(2) Compensation Committee Member
(3) Environmental & Safety Committee Member

OFFICERS

Peter A. Carwardine
President & Chief Executive Officer

Ross O. Drysdale
Corporate Secretary

Dave M. Humphreys
Vice President, Operations

Brian P. Kohlhammer
Vice President, Finance & Chief Financial Officer

Andy M. St.Onge
Vice President, Exploration

MANAGEMENT

Peter A. Carwardine
President & Chief Executive Officer

Gordon M. de Metz
Chief Geologist

Dave M. Humphreys
Vice President, Operations

Brian P. Kohlhammer
Vice President, Finance & Chief Financial Officer

Kerry D. Rawson
Manager, Engineering

Andy M. St.Onge
Vice President, Exploration

Darryl J. Thomlison
Manager, Evaluations & Business Development

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AUDITORS

KPMG LLP

INDEPENDENT ENGINEERS

Gilbert Laustsen Jung Associates Ltd.

BANKER

National Bank of Canada

LEGAL COUNSEL

Baker & McKenzie

TRANSFER AGENT

Olympia Trust Company

EXCHANGE LISTING

TSX Venture Exchange
Stock Symbol: VEL

ABBREVIATIONS

2-D	two dimensional
3-D	three dimensional
AECO	Alberta Energy Company Storage Facility
ARTC	Alberta Royalty Tax Credit
API	American Petroleum Institute
bbl	barrel
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
km	kilometre
mbbls	thousand barrels
mmboe	million barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
MMBTU	million British Thermal Units
NGLs	natural gas liquids
WTI	West Texas Intermediate
TSX	TSX Venture Exchange

CONVERSION OF UNITS

1.0 acre	=	0.40 hectares
2.5 acres	=	1.0 hectare
1.0 bbl	=	0.159 cubic metres
6.29 bbls	=	1.0 cubic metre
1.0 foot	=	0.3048 metres
3.281 feet	=	1.0 metre
1.0 mcf	=	28.2 cubic metres
0.035 mcf	=	1.0 cubic metre
1.0 mile	=	1.61 kilometres
0.62 miles	=	1.0 kilometre
1.0 MMBTU	=	1.054 GJ
0.949 MMBTU	=	1 GJ

Natural gas is equated to oil on the basis of 6 mcf = 1 boe

VIRTUSENERGYLTD

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